SUMMARY

Marc S. Pryor

INTRODUCTION

This Final Staff Assessment (FSA), Part III contains the California Energy Commission (Energy Commission) staff's evaluation of the Sunrise Cogeneration and Power Company (SCPC) Application for Certification (98-AFC-4) for the Sunrise Cogeneration and Power Project (SCPP). The following technical areas are enclosed: Air Quality, Public Health, Soils and Water Resources, and Biological Resources. The Biological Resources section is a revision of the analysis that was issued in Part I of the FSA. Please see Part I of the FSA for the background of the project, a description of the project, a description of staff's assessment, and a more complete introduction to the project.

Part I of the FSA was filed on October 1, 1999, and contained the following technical areas: Need Conformance, Hazardous Materials Management, Visual Resources, Waste Management, Transmission Line Safety and Nuisance, Land Use, Noise, Cultural Resources, Biological Resources, Facility Design, Geology/Paleontology, Reliability, Efficiency, Alternatives and General Conditions (includes Compliance Monitoring and general Facility Closure). Part II was filed on October 14, 1999, and contained: Worker Safety and Fire Protection, Socioeconomics, Traffic and Transportation, and Transmission System Engineering.

THE ANALYSES

AIR QUALITY

The San Joaquin Valley Unified Air Pollution Control District (District) issued the final Determination of Compliance (DOC) on November 18, 1999, and staff initiated its final air quality analysis. On November 29, 1999, California Unions for Reliable Energy (CURE) filed a Petition to the Hearing Board of the District for a hearing to review the FDOC. In its petition CURE enumerated concerns regarding the validity of the FDOC. Staff has taken CURE's concerns into account in its air quality analysis. In addition, staff has considered the comments contained in the U.S. Environmental Protection Agency's (USEPA) draft Prevention of Significant Deterioration (PSD) permit,and the District's responses to comments on the Preliminary DOC (PDOC) made by staff, CURE, USEPA and the applicant.

CONSTRUCTION IMPACTS

Staff concluded that the project's construction related potential air quality impacts would all be mitigated to a level of less than significant if the proposed mitigation measures are adopted.

OPERATIONS IMPACTS

At present the DOC is, in staff's opinion, not in conformance with the District's rules, specifically Rule 2201, Section 4.2. Therefore, staff cannot at this time recommend approval of the Sunrise Cogeneration and Power Project. However, presuming that the issue of conformance with the rules can be resolved, staff proposes Conditions of Certification except for the areas of nonconformance.

Staff anticipates that additional analysis will be necessary in the near future, dependent upon the outcome of CURE's petition and the District's consideration of the material in this FSA section. If so, staff also anticipates new and/or revised Conditions of Certification will be necessary as well.

PUBLIC HEALTH

The Public Health analysis has close ties with the Air Quality analysis and has been timed for issuance with the latter. In addition, due to concerns provided by CURE in the areas of Air Quality, Biological Resources and Waste Management, staff has included discussion and analysis addressing the issues raised by CURE.

Since no significant public health impacts are considered likely by staff for the project as proposed, no Public Health Conditions of Certification are proposed.

BIOLOGICAL RESOURCES

As noted above, staff issued its Biological Resouces FSA section on October 1, 1999. Since that time additional concerns have been raised by CURE regarding potential impacts to wildlife from hydrogen sulfide (H2S) emissions and wastewater disposal. Staff has revised its Biological Resources section in order to address the comments and testimony. Staff has determined that this is insufficient scientific evidence to suggest there is a significant affect to wildlife from H2S emissionsAn unresolved issue is whether the project's waste stream, that is proposed to be disposed of at Valley Waste, will contribute to potential impacts to birds utilizing unscreened sediment ponds at the waste disposal facility.

Nonetheless, staff has provided Conditions of Certification that, if adopted, it believes will mitigate to a level of less than significant, any potential significant enviromental effects on biological resources related to the proposed project.

SOIL AND WATER RESOURCES

Staff's Soil and Water Resources analysis has also taken into consideration concerns expressed by CURE, the state Department of Toxic Substances Control (DTSC) and others. There are unresolved questions regarding potential hazardous waste treatment and disposal.

CONCLUSIONS AND RECOMMENDATIONS

With regard to these four technical areas, staff cannot at this time recommend certification of the proposed project due to:

1. Staff's belief that the proposed project is not in conformance with the air District's rules, specifically Rule 2201, Section 4.2.
2. The lack of sufficient information to ascertain whether or not birds will be adversely affected at the Valley Waste facility.
3. Unresolved questions regarding potential hazardous waste treatment and disposal.

AIR QUALITY

Joseph M. Loyer
and Mark Hesters for Transmission Issues

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to the construction and operation of the proposed Sunrise Cogeneration and Power Project (Sunrise). Criteria air pollutants are defined as those for which a state or federal ambient air quality standard has been established to protect public health. They include nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), ozone (O3), volatile organic compounds (VOC), particulate matter less than 10 microns in diameter (PM10) and hydrogen sulfide (H_2S).

In carrying out this analysis, the California Energy Commission staff evaluated the following major points:

- whether the Sunrise project is likely to conform with applicable Federal, State and San Joaquin Valley Unified Air Pollution Control District air quality laws, ordinances, regulations and standards, as required by Title 20, California Code of Regulations, section 1744 (b);
- whether the Sunrise project is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, section 1742 (b); and
- whether the mitigation proposed for the Sunrise project is adequate to lessen the potential impacts to a level of insignificance, as required by Title 20, California Code of Regulations, section 1742 (b).

Issues regarding the potential effects on power plant emissions due to transmission congestion from power plants being sited in the San Jaoquin Valley are addressed by Mark Hesters in Appendix B.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

Under the Federal Clean Air Act (42 USCA § 7401 et seq.), there are two major components of air pollution control requirements for stationary sources, New Source Review (NSR) and Prevention of Significant Deterioration (PSD). NSR is a regulatory process for evaluation of those pollutants that violate federal ambient air quality standards. Conversely, PSD is a regulatory process for evaluation of those pollutants that do not violate federal ambient air quality standards. The NSR analysis has been delegated by the Environmental Protection Agency (EPA) to the San Joaquin Valley Unified Air Pollution Control District (District). The EPA determines the conformance with the PSD regulations. The PSD requirements apply only to those projects (known as major sources) that emit more than 100 tons per year for any pollutant.

STATE

The California State Health and Safety Code, section 41700, requires that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerate number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property."

LOCAL

The proposed project is subject to the following San Joaquin Valley Unified Air Pollution Control District (District) rules and regulations:

RULE 2201 - NEW AND MODIFIED STATIONARY SOURCE REVIEW RULE

The main functions of the District's New Source Review Rule are to allow for the issuance of Authorities to Construct, Permits to Operate, the application of Best Available Control Technology (BACT) to new permit sources and to require the new permit source to secure emission offsets.

SECTION 4.1 - BEST AVAILABLE CONTROL TECHNOLOGY

Best Available Control Technology is defined as: a) has been contained in any State Implementation Plan and approved by EPA; b) the most stringent emission limitation or control technique that has been achieved in practice for a class of source, or c) any other emission limitation or control technique which the District's Air Pollution Control Officer (APCO) finds is technologically feasible and is cost effective. BACT will apply to any air pollutant that results in an emissions increase of 2 pounds per day. In the case of the Sunrise project, BACT will apply for NO_x, SO_2, PM10, VOC and CO emissions from all point sources of the project.

SECTION 4.2 - OFFSETS

Emissions offsets for new sources are required when those sources exceed the following emissions levels:

- Sulfur oxides - 150 lbs/day
- PM10 - 80 lb./day
- Oxides of nitrogen - 10 tons/year
- Volatile organic compounds - 10 tons/year

The Sunrise project exceeds all of the above emission levels; therefore offsets are required for all four of these pollutants. The emission offsets provided shall be adjusted according to the distance of the offsets from the project proposed site.

The ratios are:

- Within 15 miles of the same source - 1.2 to 1
- 15 miles or more from the source - 1.5 to 1

Section 4.2.5.3 allows for the use of interpollutant offsets (including PM10 precursors for PM10) on a case-by-case basis, provided that the Sunrise Cogeneration and Power Company (SCPC) demonstrates that the emissions increase will not cause a violation of any ambient air quality standard. The ratio for interpollutant trading shall be based on an air quality analysis and shall be equal to or greater than the minimum offsetting requirements (the distance ratios) of this rule.

SECTION 4.3 - ADDITIONAL SOURCE REQUIREMENTS

Rule 4.3.2.1 requires that a new source not cause, or make worse, the violation of an ambient air quality standard as demonstrated through analysis with air dispersion models.

RULE 2520 – FEDERALLY MANDATED OPERATING PERMITS

Requires that a project owner file a Title V Operating Permit from EPA with the District within 12 months of commencing operation. A project is subject to this requirement if any of the following apply: the project is a major stationary source (under PSD definitions), it has the potential to emit greater than 100 tons per year of a criteria pollutant, any equipment permitted is subject to New Source Performance Standards, the project is subject to Title IV Acid Rain program, or the owner is required to obtain a PSD permit from EPA. The Title V permit application requires that the owner submit information on the operation of the air polluting equipment, the emission controls, the quantities of emissions, the monitoring of the equipment as well as other information requirements.

RULE 2540 – ACID RAIN PROGRAM

A project greater than 25 MW and installed after November 15, 1990, must submit an acid rain program permit application to the District. The acid rain requirements will become part of the Title V Operating Program (Rule 2520). The specific requirements for the Sunrise project will be discussed in the “Compliance with LORS – Local” later in this analysis.

RULE 4001 - NEW SOURCE PERFORMANCE STANDARDS

Specifies that a project must meet the requirements of the Federal New Source Performance Standards (NSPS) specified in Title 40, Code of Federal Regulations, Part 60, Chapter 1. Subpart GG, which pertains to Stationary Gas Turbines, requires that NO_x concentrations are a function of the heat rate of the combustion, which in this case would be approximately 116 ppmv at 15% O_2. In addition, the SO_2 concentration shall be less than 150 ppmv and the sulfur content of the fuel shall no greater than 0.8 percent by weight.

Rule 4101 - Visible Emissions

Prohibits air emissions, other than water vapor, of more than Ringelmann No. 1 (20 percent opacity) for more than 3 minutes in any one hour.

Rule 4201 - Particulate Matter Concentration

Limits particulate emissions from sources such as the gas turbines, cooling towers and emergency fire water pumps to less than 0.1 grain per cubic foot of exhaust gas at dry conditions.

Rule 4703 - Stationary Gas Turbines

Limits NO_x concentrations to 12.2 ppm for the SCR controlled turbines. In addition there is a limit in CO concentrations of less than 200 ppm.

Rule 4801 - SO_2 Concentration

Limits the SO_2 concentration emitted into the atmosphere to no greater than 0.2 percent by volume.

Rule 8010 - Fugitive Dust Administrative Requirements for Control of Fine Particulate Matter (PM-10)

Specifies the types of chemical stabilizing agents and dust suppressant materials that can (and cannot) be used to minimize fugitive dust.

Rule 8020 - Fugitive Dust Requirements for Control of Fine Particulate Matter (PM-10) from Construction, Demolition, Excavation, and Extraction Activities

Requires that fugitive dust emissions during construction activities be limited to no greater than 40 percent opacity by means of water application or chemical dust suppressants. The rule also encourages the use of paved access aprons, gravel strips, wheel washers or other measures to limit mud or dirt carry-out onto paved public roads.

Rule 8030 - Control of PM10 from Handling and Storage of Bulk Materials

Limits the fugitive dust emissions from the handling and storage of materials. It specifies that bulk materials be transported using wetting agents, allow appropriate freeboard space in the vehicles, or be covered. It also requires that stored materials be covered or stabilized.

Rule 8060 - Control of PM10 from Paved and Unpaved Roads

Specifies the width of paved shoulders on paved roads or the use of chemical dust suppressants on unpaved roadways, shoulders and medians.

RULE 8070 - CONTROL OF PM10 FROM VEHICLE/EQUIPMENT PARKING, SHIPPING, RECEIVING, TRANSFER, FUELING AND SERVICE AREAS

This rule is intended to limit fugitive dust from unpaved parking areas by means of using water or chemical dust suppressants or the use of gravel. It also requires that the affected owners/operators shall remove tracked out mud and dirt onto public roadways once a day.

ENVIRONMENTAL SETTING

METEOROLOGICAL CONDITIONS

Hot dry summers and mild winters with relatively small amounts of precipitation typically dominate the climate of the southern San Joaquin Valley. The semi-permanent Pacific High over the eastern Pacific Ocean dominates the weather during the summer months, blocking low pressure systems from passing through the area. The Pacific High, along with the Temblor Range to the west that blocks the marine air influence from the Pacific Ocean, results in summers that are usually quite warm, with average daily maximum temperatures during July of over 98^{o}F.

During the winter months, the Pacific High weakens and migrates to the south allowing Pacific storms into California. The annual rainfall in the Bakersfield area is only 5.7 inches. In between storms, high pressure from the Great Basin High can block storms and result in persistent tule fog caused by temperature inversions. Daily maximums during the December-January months are a relatively mild 57^{o}F, with lows averaging 38^{o}F. At the Maricopa weather station, a record high of 115^{o}F and record low of 15^{o}F was measured. These temperatures are used in determining the maximum possible emissions from the project and the maximum emission impacts in the air dispersion modeling analysis.

Winds in the area are strongly influenced by the Temblor Range to the west and the marine air that enters the Central Valley through the Carquinez Strait and Altamont Pass in the Bay Area to the north. During the summer, marine air entering the Central Valley results in northeasterly winds in the daytime hours. In the nighttime hours downslope drainage of air from the hills and mountains to the south and west results in winds from the southwest. This windflow pattern is fairly consistent throughout the year, although there is more variability to wind directions during the winter with the passage of storms through the area. Winds are usually of higher speeds during the summer because during the winter, calm and stagnant atmospheric conditions can occur between storms and the influence of the marine air from the coast is significantly diminished.

Along with the winds, another climatic factor affecting emission impacts is atmospheric stability and mixing height. Atmospheric stability is an indicator of the air turbulence and mixing. During the daylight hours of the summer when the earth is heated and air rises, there is more turbulence, more mixing and thus less stability. During these conditions there is more air pollutant dispersion and therefore usually fewer air quality impacts from a single air pollution source like the Sunrise project.

During the winter months between storms, very stable atmospheric conditions occur, resulting in very little mixing. Under these conditions, little air pollutant dispersion occurs, and consequently higher air quality impacts result from stationary source emissions. Mixing heights are generally lower during the winter, along with lower mean wind speeds and less vertical mixing.

EXISTING AIR QUALITY

The Federal Clean Air Act and the California Air Resources Board (CARB) both require the establishment of allowable maximum ambient concentrations of air pollutants, called ambient air quality standards (AAQS). The state AAQS, established by CARB, are typically lower (more protective) than the federal AAQS, which are established by the EPA. The state and federal air quality standards are listed in AIR QUALITY Table 1. As indicated in AIR QUALITY Table 1, the averaging times for the various air quality standards (the duration over which they are measured) range from one-hour to one year. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 and $\mu g/m^3$).

In July 1997, the EPA promulgated new ozone and PM2.5 (particulate matter less than 2.5 microns in diameter) ambient air quality standards, which are shown in AIR QUALITY Table 1. The new 8-hour ozone standard will replace the existing 1-hour standard. The PM2.5 standards will be in addition to the existing PM10 standards. Although the standards may be set, the EPA will first have to designate areas which violate these new standards, and then air districts that violate these standards will have to prepare implementation plans to reach attainment of those standards. Additionally, these standards have been contested and overturned in court.

In general, an area is designated as attainment for a specific pollutant if the concentrations of that air contaminant do not exceed the standard. Likewise, an area is designated as non-attainment for an air contaminant if that standard is violated. Where not enough ambient data are available to support designation as either attainment or non-attainment, the area can be designated as unclassified. Unclassified areas are normally treated the same as attainment areas for regulatory purposes. An area can be attainment for one air contaminant while non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same contaminant. The entire area within the boundaries of a district is usually evaluated to determine the district’s attainment status.

AIR QUALITY Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O3)	1 Hour	0.12 ppm (235 μg/m^3)	0.09 ppm (180 μg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual Average	0.053 ppm (100 μg/m^3)	---
	1 Hour	---	0.25 ppm (470 μg/m^3)
Sulfur Dioxide (SO_2)	Annual Average	80 μg/m^3 (0.03 ppm)	---
	24 Hour	365 μg/m^3 (0.14 ppm)	0.04 ppm (105 μg/m^3)
	3 Hour	1300 μg/m^3 (0.5 ppm)	---
	1 Hour	---	0.25 ppm (655 μg/m^3)
Respirable Particulate Matter (PM10)	Annual Geometric Mean	---	30 μg/m^3
	24 Hour	150 μg/m^3	50 μg/m^3
	Annual Arithmetic Mean	50 μg/m^3	---
Fine Particulate Matter (PM2.5)	24 Hour	65 μg/m^3	---
	Annual Arithmetic Mean	15 μg/m^3	---
Sulfates (SO_4)	24 Hour	---	25 μg/m^3
Lead	30 Day Average	---	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	---
Hydrogen Sulfide (H_2S)	1 Hour	---	0.03 ppm (42μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	---	0.010 ppm (26 μg/m^3)
Visibility Reducing Particulates	1 Observation	---	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

The Sunrise project is located in the Kern County portion of the San Joaquin Valley Air Basin and, as stated above, is under the jurisdiction of the San Joaquin Valley Unified Air Pollution Control District. This area is designated as non-attainment for both the state and the federal ozone and PM10 standards, attainment for the state's CO, NO_2, SO_2, SO_4 and Lead standards, attainment for the federal SO_2 standard, and unclassified/attainment for the federal CO and NO_2 standards (ARB 1998).

Ambient air quality data has been collected by the oil companies, known as the Westside Operators, in western Kern County for a number of years. Ambient air quality data collected between 1992 and 1995 at the Westside Operators Fellows site, located approximately 4 miles south-southeast of the project site is presented in AIR QUALITY Table 2. That data shows there have been no violations during that period of the NO_2, SO_2 or CO ambient air quality standards.

Additional ambient air quality data from the Air Resources Board's ozone monitor in Maricopa (18 miles south-southeast of the project site) and Taft College PM10 monitor (10 miles south-southeast of the project site) are shown in AIR QUALITY Table 3. This data shows that frequent violations of the state 1-hour ozone and 24-hour PM10 standard have occurred between 1992 and 1997. There appears to be no clear trend of significant improvement in the ambient concentrations of these two pollutants.

OZONE

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted air pollutants. Nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds [VOCs]) interact in the presence of sunlight to form ozone. The collected air quality data indicate that the ozone violations occurred primarily during the period of May through October.

In the most recent ARB report on the contribution of various districts to ozone violations in other districts (ARB 1996), ARB concluded that the San Joaquin Valley Air Basin contributes measurably to ambient ozone levels in other districts, and that other districts contribute measurably to the San Joaquin Valley's ozone problems. The report concludes that sources within the San Joaquin Valley Air Basin contribute to ozone levels in Mountain County districts to the northeast, the South Central Air Basin to the south, to the Mojave Desert to the east, the Sacramento area to the north, the Great Basin Valleys to the east, and to the North Central Coast Air Basin to the west. Conversely, emissions from districts such as the Bay Area Air Quality Management District and the Sacramento Air Quality Management District contribute to San Joaquin Valley's ozone problems. This widespread contribution from one geographic area to another demonstrates the regional nature of the ozone problem and ozone formation.

AIR QUALITY Table 2
PM10, NO_2, CO and SO_2 Ambient
Air Quality Data Collected at Fellows

Pollutant	Averaging Time	1995	1994	1993	1992	Most Restrictive Ambient Air Quality Standard
PM10	24 hours	80	85	109	104	50
	Annual	24.6	25.9	31.0	35.7	30
NO_2	1 hour	62	94	92	84	470
	Annual	12.6	14.4	16.6	20.6	100
CO	1 hour	2440	2303	2941	2713	23,000
	8 hour	1869	1985	2222	1783	10,000
SO_2	1 hour	65	94	36	78	655
	3 hours	36	57	27	52	1300
	24 hours	13	20	14	14	130
	Annual	1.5	1.8	1.8	1.7	80

AIR QUALITY Table 3
Ozone and PM10 Ambient Air Quality Data

Pollutant & Location		1997	1996	1995	1994	1993	1992
Ozone Maricopa	Max. conc.(ppm)	.12	.12	.13	.13	.12	0.11
	# days exceed standard	24	63	57	11	17	25
PM10 Taft College	Max. conc. ($\mu g/m^3$)	78	94	93	64	118	110
	# days exceed standard	6	12	15	6	13	15
	% of samples above 24-hour standard	10%	20%	25%	11%	23%	25%
California Ozone Ambient Air Quality Standard: 0.09 ppm (1-hour average) National Ozone Ambient Air Quality Standard: 0.12 ppm (1-hour average) California PM10 Ambient Air Quality Standard: 50 $\mu g/m^3$ (24-hour average)							

AMBIENT PM10

As Table 3 indicates, the project area also annually experiences a number of violations of the state 24-hour PM10 standard, although violations of the federal 24-hour standard are not occurring. The violations of the state 24-hour standard occur predominately between the months of August and February, with the highest number of violations occurring from September through November.

PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SO_x and VOC from turbines, and ammonia from NO_x control equipment can, given the right meteorological conditions, form particulate matter known as nitrates (NO3), sulfates (SO4), and organics. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions in the atmosphere.

A number of studies have been undertaken to understand the particulate phenomenon, both PM10 and the smaller PM2.5, in the San Joaquin Valley. Major sources of information on the subject are available from the District and CARB. Staff has concluded the following about the NOx/PM10 relationship:

- NO_x emissions contribute significantly to the formation of particulate nitrate in the region where the Sunrise project is located, and
- ammonium nitrate is the largest contributor to PM10 levels during the winter when ambient PM10 levels are at there highest.

Staff's assessment of the NO_x contribution to particulate nitrate formation is that emissions of gaseous NO_x emissions can contribute a substantial portion of the ambient particulate nitrate in the southern San Joaquin Valley, especially during the winter season when the PM10 levels are the highest.

PROJECT DESCRIPTION AND EMISSIONS

CONSTRUCTION

The Sunrise project will include not only the power plant, but the following ancillary facilities as well:

- a 230 kilovolt (kV) substation on the east end of the Sunrise project site,
- a 22 mile-long, 230 kV transmission line (several routes are being considered at this time, however staff will present only the preferred route which is route B),
- a 60 foot-long, 12 inch diameter natural gas pipe line that will tie into the Texaco California Inc. (TCI) Main Utility Corridor,
- three separate 600 foot-long lines for steam, boiler feed water and waste water that will tie into the TCI Main Utility Corridor,

- and three (3) 30 foot-long fresh water lines that will tie into the West Kern Water lines, south of the site.

The construction of these facilities will generate air emissions, primarily fugitive dust from earth moving activities and combustion emissions generated from the construction equipment and vehicles. The projected highest daily emissions, based on the highest monthly emissions over the 15 months of construction activity are shown in AIR QUALITY Table 4. It should be noted that the emissions shown in Table 4 would likely not occur on one single day.

AIR QUALITY Table 4
Maximum Daily Construction Emissions (lbs./day)

	NOx	VOC	CO	PM10	SOx	Fugitive PM10
Project Site & 230kV substation	221	37	314	24	21	154[a]
Transmission line	132	15	55	15	12	Negligible
Natural gas pipeline	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible
Steam, boiler water and waste water lines	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible
Fresh water line	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible
Emission estimates assume an 8-hour workday. a – Fugitive dust emission estimate assumes no controls.						

PROJECT SITE

The power plant itself will take approximately 15 months to construct. The power plant project construction consists of three major areas of activity: 1) the civil/structural construction 2) the mechanical construction, and 3) the electrical construction. The greatest level of air emissions are generated during the civil/structural activity, where work such as grading, site preparation, foundations, utility installation and building erection occur. These types of activities require the use of large earth moving equipment, which generates considerable combustion emissions, along with creating fugitive dust emissions. The mechanical construction includes the installation of the heavy equipment, such as the combustion turbines, the heat recovery steam generators, pumps, piping and valves. Although not a large fugitive dust generation activity, the use of large cranes to install such equipment generates significantly more emissions than other construction equipment onsite. Finally, the electrical equipment installation occurs involving such items as transformers, switching gear, instrumentation and wiring. This is a relatively small emission generating activity in comparison to the early construction activities.

TRANSMISSION LINE

The construction of the transmission line is planned to take approximately 8 months between the 1st and 8th month of the project construction schedule. The significant emissions generating vehicles are the trucks used to deliver the transmission tower structural materials, boom trucks and mobile cranes (Radian 1999c). Maximum emissions from the transmission line construction are shown in AIR QUALITY Table 4. The SCPC has discussed several different options for the transmission line route; however, all the options should result in very similar emissions and impacts. Therefore staff will analyze only the currently preferred route (route B in the AFC) and assume that all alternative routes have similar emissions or less. Route B (also routes D, E and F) is approximately 22 miles long and generally heads towards the north through the Midway-Sunset and La Paloma power plants ending in the Midway Substation. There might be some minor expansion construction performed at the Midway substation. It is staff's opinion that whichever route is chosen (B, D, E, F or G) the air emissions and impacts will be very similar.

OPERATIONAL PHASE

EQUIPMENT DESCRIPTION

- The major components of the Sunrise project consist of the following: two combustion turbine generators (CTG), using the General Electric (GE) Frame 7 FA each with a generating capacity of 165 MW (gross). Each of the CTGs would be equipped with evaporative inlet air coolers;
- Two unfired heat recovery steam generators (HRSG) and ancillary equipment;

EQUIPMENT OPERATION

The CTGs will burn only natural gas, and there are no provisions for an alternative back-up fuel.

SCPC is requesting that the project be analyzed with the assumption of 20 startups per turbine each year. The duration of a startup is relatively short, approximately 20 minutes. However, in order to allow for failed startup attempts staff recommends that the SCPC be allowed 1 hour for each startup.

EMISSION CONTROLS

The exclusive use of an inherently clean fuel, natural gas, will limit the formation of SO_2 and PM10 emissions. Natural gas contains very small amounts of a sulfur compound known as mercaptan, which when combusted, results in sulfur dioxide emissions in the flue gas. However, in comparison to other fuels used in power plants, such as fuel oil or coal, the sulfur dioxide emissions from the combustion of natural gas are very low.

Like SO_2, the emissions of PM10 from natural gas combustion are very low compared to the combustion of fuel oil or coal. Natural gas contains very little noncombustible gas or solid residue; therefore, it is a relatively clean-burning fuel.

A sulfur content of 0.75 grains of sulfur per 100 standard cubic feet of natural gas was assumed for the SO_2 emission calculations.

To minimize NOx, CO and VOC emissions during the combustion process, the GE 7FA turbine is equipped with dry low-NO_x combustor design developed by General Electric (GE). A more detailed discussion of this combustion technology is presented in the Mitigation section of this analysis.

After combustion, the flue gases pass through the heat recovery steam generator (HRSG), where catalyst systems are placed to further reduce NO_x emissions. SCPC is proposing to use a Selective Catalytic Reduction (SCR) system to reduce NO_x emissions. A more complete discussion of this catalyst is included in the Mitigation section.

PROJECT OPERATING EMISSIONS

The proposed project's criteria air pollutant emissions during startup, shutdown and full load conditions are shown in AIR QUALITY Table 6. This table presents the combustion turbine emissions only. As this table shows, the highest emissions will occur during startup and shutdown, and are significantly higher than those during steady state, full load operation. This is particularly true for NOx, VOC and CO emissions. These higher emissions occur because the turbine combustor technology is designed for maximum efficiency during full load steady state operation.

AIR QUALITY Table 6
Project (Per CTG) Hourly Emissions
(pounds per hour [lbs/hr] except where noted)

Operational Profile	NO_x	SO_2	PM10	VOC	CO
CTG Startup (assuming three 20-minute events)	96	0	21.0	51.0	489
CTG Shutdown (assuming three 20-minute event)	96	0	21.0	51.0	489
CTG 100% load at 15°F	16.5	3.5	9.0	2.8	24.1
CTG 100% load at 65°F	15.4	3.3	9.0	2.6	22.5
CTG 100% load at 115°F	14.4	3.1	9.0	2.5	25.2
2 CTGs 100% load at 65° F	30.8	6.6	18.0	5.2	45.0

During startup and shutdown, combustion temperatures and pressures are rapidly changing, which results in less efficient combustion and higher emissions. Also, the flue gas controls, the SCR discussed above, operate most efficiently when the turbine operates near or at full load. Those flue gas controls are not as effective during the transitory temperature changes that occur during startup and shutdown.

The startup emission estimates reflect information provided by GE to the SCPC, which is included in the AFC. Each startup attempt should last approximately 20-minutes and is assumed to have equivalent emissions as if the turbine were operating at 60% load for an hour. That is, the mass of pollutants that would be emitted in one hour of operation at 60% load are the same as the mass of pollutants that would be emitted during one 20-minute startup. The SCPC makes the conservative assumption that the shutdown emissions will be similar to the startup emissions, which will not be the case. Shutdown emissions, although higher than steady state emissions, are typically significantly less than the startup emissions because the system is operating at maximum efficiency and the post-combustion control systems are functioning.

Starting up a simple-cycle cogeneration power plant is a short duration event (20 minutes in most cases). However, from time to time the turbine fails to startup and the operators must attempt another startup. Therefore, to be conservative, staff assumes that the operators will attempt no more than three consecutive startups. In reality, it is very unlikely that any operator would go this far before determining and rectifying the cause of a failed startup attempt. AIR QUALITY Table 6 shows that the highest one-hour emission rate is for the assumed startup scenario of three consecutive 20-minute startup attempts.

AIR QUALITY Table 6 also shows the operational emission rate for PM10 to be 9 lbs/hr. This is half of what the vendor will guarantee (18 lbs/hr). Sunrise justifies this emission level by identifying measured PM10 emission in other similar power plants currently in operation. There are two components in the source test measurement of PM10, the filterable (front half) and the condensable (back half). Staff reviewed the summary of PM10 source tests provided by California Unions for Reliable Energy (CURE). It demonstrated that the condensable fraction is in many cases as high as the filterable fraction, particularly for power plants in the southern San Joaquin Valley. However, the only combustion turbine trains (7F models) that are close in size and configuration to the SCPP is the Crockett Cogeneration Project, located in the Bay Area. In 1998, the Crockett Project recorded filterable PM10 at 2.82 lbs/hr. Previous source tests in 1996 and 1997 showed filterable PM10 at 2.3 lbs/hr or less. Based on these measurements and the indications that other smaller combustion turbines can produce similar results, staff is comfortable using the 9 lbs/hr estimate as a PM10 emission limit for the SCPP.

The daily emissions from the project are shown in AIR QUALITY Table 7 for CTG startup and steady state operation.

AIR QUALITY Table 7
Project Daily Emissions
(pounds per day [lbs/day])

Operational Profile	NO_x	SO_2	PM10	VOC	CO
2 turbine sequential startup and steady state operation	951	161	456	231	2087
Typical daily operation - 2 turbines operate full load, with no startups.	792	168	432	134	1157

Annual emissions are summarized in AIR QUALITY Table 8. SCPC has requested that the project be analyzed assuming 20 startups per turbine per year, and 20 shutdowns per turbine per year. The balance of the year's operation assumes full load operation of the CTGs. This type of operational scenario is actually not possible, since by definition, the startups must be preceded with no turbine operation and thus no emissions. In most cases, the turbines would likely be down for many days before a startup would be initiated. Therefore, the assumption of 8720 hours of steady state operation and 20 startups and shutdowns could not happen.

For comparison, staff has presented the scenario of both turbines operating non-stop throughout the year. Typically, the highest annual emissions of SO_2 and PM10 would occur with this scenario. However, in this case the emissions of SO_2 and PM10 for 20 startups/shutdowns and 8720 hours of operation are similar to the emissions assuming 8760 hours of steady state operations because of staff's startup assumptions. The annual emissions of NOx, VOC and CO are higher because they include startup emissions.

AIR QUALITY Table 8
Project Annual Emissions
(tons per year [ton/yr])

Operational Profile	NO_x	SO_2	PM10	VOC	CO
20 startups, 20 shutdowns, steady state operation[a]	137.9	28.8	79.3	24.7	215.9
Steady state operation entire year[b]	134.9	28.9	78.8	22.8	197
Notes: a- Assumes 20 1-hr startups, 20 1-hr shutdowns and 8720 hours normal full load operation per turbine @ 65°F. Includes both turbines. b- Assumes 8760 hr normal full load operation, both turbines.					

AMMONIA EMISSIONS

Due to the large combustion turbines used in this project and the need to control NO_x emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia mixes in the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered, out the stack. These ammonia emissions are known as ammonia slip. SCPC has committed to an ammonia slip no greater than 10 ppm, which is the current ammonia slip level being permitted throughout California. On a daily basis, the ammonia slip of 10 ppm is equivalent to approximately 1,166 lbs/day of ammonia emitted into the atmosphere.

It should be noted that an ammonia slip of 10 ppm is usually associated with the degradation of the SCR catalyst, usually in a time frame of five years or more after initial operation. At that point, the SCR catalysts are removed and replaced with new catalysts. During most of the operation of the SCR system, ammonia slip emissions are usually in the range of 1 to 2 ppm, corresponding to a mass emissions in the Sunrise project case to approximately 100 to 250 pounds per day. The implications of these ammonia emissions are discussed later in this analysis.

INITIAL COMMISSIONING PHASE OPERATION AND EMISSIONS

The combustion turbines will undergo an initial firing and commissioning phase prior to commercial operation. During this period, emissions may exceed permitted levels, due to startups, shutdowns, extended periods of low load operation and periods of time when the low-NO_x burners and SCR systems will need to be fine tuned for optimum performance.

The District rules and regulation do not allow for excess emissions (emissions beyond the emission limits imposed) during the initial commissioning phase of the project. The District will insist that the SCPC use the breakdown and variance regulations that currently exist in the District rules and regulations. Since there is no certainty that these excess emissions will occur during initial commissioning, staff concludes that adherence to the District breakdown and variance rules will reduce any potential impact from these emissions to a level of insignificance.

FACILITY CLOSURE

Eventually the Sunrise project will close, either because of the end of its useful life, or through some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, all sources of air emissions would cease and thus all impacts associated with those emissions would no longer occur.

A Permit to Operate, issued by the District under Rule 2010, is required for operation of the facility once it is constructed, and is usually renewed on a five year schedule. However, during those five years, the SCPC must still pay permit fees annually. If the SCPC chooses to close the facility and not pay the permit fees, then the Permit to Operate would be cancelled. In that event, the project could not restart and operate unless the fees are paid to renew the Permit to Operate.

If SCPC were to decide to dismantle the project, there would likely be fugitive dust emissions associated with this dismantling effort. District Rule 8020 requires that during demolition fugitive dust emissions be limited to no greater than 40% opacity by means of water application or chemical suppressants. The Facility Closure Plan, to be submitted to the Energy Commission Compliance Project Manager, should include the specific details regarding how SCPC plans to demonstrate compliance with the District Rule 8020 in the event of a closure.

PROJECT INCREMENTAL IMPACTS

The SCPC is proposing to produce steam for use in the nearby Texaco Western Kern County Oil Production fields. Additionally, the Sunrise project will make significant use of the partially constructed TCI Main Utility Corridor. This utility corridor will supply the Sunrise project with natural gas, as well as feedwater. It will also accept and deliver to the oil field, all available steam from the Sunrise project and take away all wastewater from the project. The Sunrise project and the TCI Main Utility Corridor are very closely linked, but are being considered separate projects for this analysis. Therefore, the TCI Utility Corridor will be discussed in more detail in the Cumulative Impacts section. The oil field expansion impacts will be discussed in the Indirect Impacts section, as will a proposed expansion to the nearby wastewater treatment facility. Project Direct Impacts section will focus on direct emissions from the proposed project during both construction and operation.

MODELING APPROACH

SCPC performed an air dispersion modeling analysis to evaluate the Sunrise project's potential impacts on the existing ambient air pollutant levels, both during construction and operation. An air dispersion modeling analysis usually starts with a screening level analysis. Screening models use very conservative assumptions, including meteorological conditions that may or may not actually occur in the area. The impacts calculated by screening models, therefore, can be more than double the actual or expected impacts. If the screening level impacts are significant, refined modeling analysis is performed. A major difference in the refined modeling is that hour-by-hour meteorological data collected near the project site is used. The Industrial Source Complex Short-Term model, Version 3, known as the ISCST3 model, was used for the refined modeling.

PROJECT DIRECT IMPACTS

CONSTRUCTION IMPACTS

SPCP performed air dispersion modeling analyses of the potential construction impacts at the project site. The analyses included fugitive dust generated from the construction activity (modeled as an area source) and combustion emissions from the equipment (modeled as point sources). The emissions used in the analysis were the highest emissions of a particular pollutant during a one month period, converted to a gram per second emission rate for the model. Most of the highest emissions occurred in the initial months of the 15-month construction period. The results of this modeling effort are shown in AIR QUALITY Table 9. They show that the construction activities would cause a violation of the state 24-hour and annual average PM10 standards. In reviewing the modeling output files, staff determined that the project's construction impacts are not occasional or isolated events, and occur over an area within a few hundred meters of the project site. These predicted impacts are of a high magnitude for a number of reasons.

AIR QUALITY Table 9
Maximum Construction Impacts

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	298[a]	97	395	470	84%
	Annual	9.6[b]	20.6	30.2	100	30%
CO	1-hour	1,486	2,941	4,427	23,000	19%
	8-hour	680	2,222	2,902	10,000	29%
SO_2	1-hour	99	104	203	655	31%
	3-hour	67.9	68	135.9	1300	10%
	24-hour	23.3	38	61.3	130	47%
	Annual	1.2	1.8	3	80	3.75%
PM10	24-hour	137	118	255	50	510%
	Annual	9.3	42.6	51.9	30	173%

a – Results obtained using the Ozone Limiting Method (OLM).

b – Results obtained using the Ambient Ratio Method (ARM) default value 0.75.

First, the model itself calculates impacts that are conservative, usually exceeding actual impact levels. Second, some of the sources of combustion emissions (the bulldozers and trucks) are mobile sources, not stationary sources, as assumed in the input to the model. As mobile sources, the air quality impacts would not always be at the same locations. Third, it was assumed that all the equipment identified for the modeling evaluation would be running simultaneously. It is doubtful that all the major equipment would all be operating at one time. Finally, the emissions inputs to the model were from the highest monthly emissions assumed during the 15-month construction period. The levels of emissions used reflect a period of activity of approximately 4 months, not the entire 15-month construction. During the other months of construction work, considerably fewer pieces of emission generating equipment will be used and thus the impacts will be lower.

Therefore, although the modeling results for the construction of the Sunrise project predict an impact on the PM10 ambient air quality standards, it is doubtful that the general public would be exposed to these impacts. However, it is not possible to determine to what extent the modeling results are over estimating the Sunrise project construction emission impacts. Therefore, staff concludes that the emissions from the construction of the Sunrise project have the potential to cause unavoidable short-term significant impacts on the PM10 ambient air quality standards if left unmitigated.

PROJECT OPERATION IMPACTS

The potential air quality impacts of the Sunrise project operation are discussed in the following sections for fumigation meteorological conditions, combustion turbine startup and combustion turbine steady-state operations.

FUMIGATION

During the early morning hours before sunrise, the air is usually very stable. During such stable meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed. When the sun first rises, the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air will also be vertically mixed, bringing some of those emissions down to ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, and the emissions plume becomes better dispersed. The early morning air pollution event, called fumigation, usually lasts approximately 30 to 90 minutes. Since fumigation impacts will not typically occur much beyond a 1-hour period, only impacts on 1-hour standards are addressed. AIR QUALITY Table 10 shows the results of the fumigation modeling that the SCPC performed. These results demonstrate that the 1-hour standards for NO_2, SO_2 and CO are not exceeded under fumigation conditions for the Sunrise Project. Therefore, staff concludes that under fumigation conditions, the Sunrise project emissions have no potential to cause a significant impact on the ambient air quality standards.

AIR QUALITY Table 10
1-hour Fumigation Modeling Results

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	23.8	97	121	470	26%
CO	1-hour	107.49	2,941	3,048	23,000	13%
SO_2	1-hour	1.60	104	106	655	16%
(SCPP 1999l)						

STARTUP, SHUTDOWN AND STEADY STATE OPERATIONS

SCPC provided a refined modeling analysis, using the ISCST3 model to quantify the potential impacts of the Sunrise project both during normal steady state operation and during startup or shutdown conditions. The startup circumstances of the project are such that the combustion turbines will be started sequentially. That is, there will be no simultaneous startup of the two turbines. A startup sequence of a turbine will only occur when the other turbine is operating at steady state or is not operating at all. Startup conditions can cause short-term build ups in local ambient air pollution levels for the following reasons. First, emissions (particularly of NO_x and CO) can be high and often uncontrolled, because emission control equipment is not operating at optimum temperature ranges. Second, low volumetric flow rates and exhaust gas temperatures can result in low exhaust plume rise and consequently higher ground level impacts.

The modeling analysis provided by the SCPC does not reflect the 1-hour startup that staff has assumed. The SCPC modeling analysis assumes that both turbines would startup simultaneously and then operate at full (100%) capacity for 40 minutes. As previously discussed, staff assumes that the turbine startup will require 1 hour (three consecutive 20-minute attempts). Further, staff assumes that while one turbine is attempting startup, while the other turbine is operating at full load. Staff feels that this scenario represents the highest emissions that can be reasonably expected in a 1-hour operating scenario.

Any ISCST3 model impact prediction is directly proportional to the assumed emission rate at the modeled source. If all other factors are held constant and the source emission rate is changed, then the impact at the same location changes proportionally. Staff has determined the proportional increase for each pollutant in the original 1-hour modeling analysis and has shown them in AIR QUALITY Table 11. Staff multiplied the ratios in the last column of AIR QUALITY Table 11 by the modeling results supplied by the SCPC, see AIR QUALITY Table 12.

AIR QUALITY Table 11
Proportional Increase Factors for Modeled Impact Results

Pollutant	Original Emission Rate[a] (g/s)	Turbine 1 Starting up[b] (lbs/hr)	Turbine 2 Operating Full Load[b] (lbs/hr)	Total Emissions (lbs/hr)	New Emission Rate[c] (g/s)	Ratio of Emission Rates (New/Old)
NO_2	5.24	96	16.5	112.5	14.17	2.70
CO	22.65	489	24.1	513.1	64.64	2.85
SO_2	0.39	0	3.5	3.5	0.44	1.13

a – (SCPC 1998a)
b – AIR QUALITY Table 6
c – unit conversion from lbs/hr to g/s is 0.12598
NOTE: g/s means grams per second, a typical unit of measure for modeling purposes.

AIR QUALITY Table 12
Combustion Turbine Refined Modeling Maximum Impacts

Pollutant	Average Time	SCPC's Modeled Impacts ($\mu g/m^3$)	Staff's Startup Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	*97*	262[a,c]	97	359	470	76%
	Annual	0.2[b,d]	na	20.6	20.8	100	21%
CO	1-hour	*418*	1193[c]	2,941	4134	23,000	18%
	8-hour	17.2[g]	na	2,222	2,239	10,000	22%
SO_2	1-hour	*7.3*	8.25[c]	104	112	655	17%
	3-hour	3.3[e]	na	68	71.3	1300	5%
	24-hour	0.5[d]	na	38	38.5	130	30%
	Annual	0.1[d]	na	1.8	2	80	2.5%
PM10	24-hour	3.1[f]	na	118	121	50	242%
	Annual	0.3[d]	na	42.6	43	30	143%

a – Results obtained using the Ozone Limiting Method (OLM).

b – Results obtained using the Ambient Ratio Method (ARM) default value 0.75.

c – Results based on three consecutive 20-minute startup attempts for one turbine while the other turbine is operating at full capacity.

d – Results based on two turbines operating at 100% load at 65^oF.

e – Results base on two turbines operating at 100% load at 15^oF.

f – Results based on two turbines operating at 60% load at 65^oF.

g – Results base on two turbines operating at 80% load at 65^oF.

AIR QUALITY Table 12 indicates that during a project startup scenario, the impacts from that startup, plus background NO_2 ambient levels would result in the highest contribution of the project to the 1-hour state NO_2 standard. This modeling analysis reflected the use of the Ozone Limiting Method (OLM) to provide a more refined estimate of NO_2 impacts. The highest SO_2 contribution to the 1-hour standard occurs during the startup scenario, that is one turbine running at full load while the other attempts 3 consecutive 20-minute startups. The highest SO_2 contribution to the 3-hour, 24-hour and annual standards occur when both turbines are running at full load. The highest PM10 contribution to the annual standard also occur when both turbines are running at full load. Startup impacts on long term standards for SO_2 and PM10 are significantly less because these emission estimates are based on fuel consumption. Since there is significantly less fuel burned during startup than at full load, there are fewer impacts. However, because of the conservative estimate for the PM10 emission rate (18 lbs/hr under all operating circumstances) the model determined that the highest PM10 impact for the 24-hour standard occurs when both turbines are operating at 60% load and the air temperature is 65^oF. Staff believes that this is simply a result of the conservative nature of the model and the original emission estimate.

AIR QUALITY Table 12 shows that the air pollution impacts would not cause a violation of any NO_2, CO or SO_2 ambient air quality standards. The project's PM10 impacts could contribute to existing violations of the state 24-hour and annual average PM10 standards. However, because of the conservatism of the air dispersion model itself, staff believes that the actual impacts from the project would be significantly less than the projected modeled impacts shown in AIR QUALITY Table 12. However, it is not possible to determine to what extent, if at all, the model may be over-predicting the PM10 impacts. Therefore, staff concludes that the emissions from the expected operation of the Sunrise project have the potential to cause significant impacts on the PM10 ambient air quality standards if left unmitigated.

VISIBILITY IMPACTS

A visibility analysis of the Sunrise project's gaseous emissions is required under the Federal Prevention of Significant Deterioration (PSD) permitting program. The analysis addresses the contributions of gaseous emissions (primarily NOx) and particulate (PM10) emissions to visibility impairment on the nearest Class 1 PSD areas, which are national parks and national wildlife refuges. The nearest Class 1 areas to the Sunrise project are the Domeland Wilderness Area 90 miles to the northeast and the San Rafael Wilderness Area 35 miles to the south. SCPC used the EPA approved model VISCREEN to assess the project's visibility impacts. The results from the VISCREEN modeling analysis indicate that the project's visibility impacts would be below the significance criteria for contrast and perception. Therefore, the project's visibility impacts on these Class 1 areas are considered insignificant.

INDIRECT IMPACTS

The indirect impacts associated with the proposed Sunrise project are those impacts that are not directly caused by the project itself, but are a result of other activities which will occur as a result of the project. These include 700 new wells associated with Texaco's expansion of the Western Kern County Oil Production fields and the proposed expansion of the associated wastewater treatment facility.

THE OIL FIELD EXPANSION

Texaco has estimated that approximately 700 new injection wells will be created as a result of the Sunrise project. The emissions associated with the construction and operation of these wells are estimated below.

WELL CONSTRUCTION

In general, the following equipment is used for the construction of most types of oil wells. For grading: 220 HP Front End Loader, 165 HP Motor Grader and a 220 HP 4000-gallon Water Truck. For Drilling: Several diesel fired engines totaling approximately 1,500 HP.

Construction of a typical injection well takes approximately one week; 2 days grading, 3 days drilling and 2 days to install the flowline, pumping unit and motor (SCPC 1999f). AIR QUALITY Table 13 shows the vehicular emission estimates for the construction and drilling of a typical well. Emissions from fugitive dust are negligible because of the small amount of earth typically being moved.

Air Quality Table 13
Construction Vehicular Emission Estimates

	NO_x	VOC	PM	SO_x	CO
Lbs/Day[a]	279.2	22.4	20.0	17.6	60.0
Lbs/Hr[b]	34.9	2.8	2.5	2.2	7.5

[a] Assumes an eight hour day
[b] As reported by CURE in their comments on the PSA, September 3, 1999.

CURE, in their comments on the Preliminary Staff Assessment, estimated the emissions reported in AIR QUALITY Table 13. Additionally, CURE performed a modeling assessment that staff believes is relevant. This modeling assessment builds on the modeling performed by the applicant and extrapolates the impacts using the new emission factors. The modeling analysis performed by the applicant assumes four point sources for all the heavy equipment used at the power plant project site, which is a reasonable and accepted practice. That modeling analysis can be used to estimate the impacts from emissions of construction equipment for well construction by substituting the well construction emission rates for the site construction emission rates and adjusting the impact results proportionally. Those modeling results are shown in AIR QUALITY Table 14. It should be noted that the emissions from oil well construction are short-term in nature. The impacts from oil well construction emissions will largely be confined to the oilfields where the public does not have access.

AIR QUALITY Table 14
Maximum Construction Impacts from a single Well

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	351	97	448	470	95%
CO	1-hour	755	2,941	3696	23,000	16%

(CURE 1999g)

The data in AIR QUALITY Table 14 show that the impacts from the construction of one well could be very close to the 1-hour NO_2 ambient air quality standard, assuming the highest background data is used. With the concurrent construction of multiple wells in close proximity, one could expect that their impact could also be very close to the 1-hour NO_2 standard. According to analysis supplied by CURE, there is a reasonable expectation that multiple wells will be constructed in close proximity (CURE 1999g). However, these impacts are short term, they are expected to not exceed 2 days in duration. If these impacts were of a longer duration, they would be significant if left unmitigated. Due to the short term nature of the impacts, staff finds that there is a reasonable expectation that no significant impact will result from the construction of multiple oil wells in the project area.

WELL OPERATION

VOC Emissions

The 700 new wells will have vapor control devices that reduce VOC emissions by 99.9%. These vapors are typically combusted at District permitted field steam generators or in rare cases in flares. These combustion sources are permitted through the District and are fully offset. Texaco estimates that the total uncontrolled fugitive VOC emissions associated with new wells (the 0.1% not controlled through the vapor recovery system) are 0.4530 lbs per well per day (SC&PP 1999f). If all 700 wells were constructed and running, that would mean 317 lbs of VOC per day or 57.9 tons per year. CURE, in their comments of the Preliminary Staff Assessment estimated that the fugitive VOC emissions associated with the new wells would be approximately 67.8 tons/year (CURE 1999g). The current and forecasted total VOC emissions from all stationary and mobile sources in the San Joaquin Valley are 490 tons/day for 1996 and 420 tons/day for 2010. The VOC emissions related to oil and gas production are 52 tons/day and 41 tons/day for 1996 and 2010 respectively (ARB 1999). The VOC emissions from the 700 new wells represent a maximum of approximately 0.45% of the 2010 VOC emission inventory for oil and gas production, assuming the emission estimate made by CURE. It should also be noted that the District new source review rule (Rule 2201) requires that all VOC emissions associated with new well development be fully offset. Therefore, staff believes that these potential emissions do not represent a significant air quality impact.

H_2S Emissions

A portion of the VOC emissions that will be created by the 700 new wells served by the project will be hydrogen sulfide (H_2S). H_2S is a criteria pollutant and increases may not be mitigated by the VOC offsets provided by the applicant. There is very little information about the current H_2S ambient air quality levels in the project area, and the San Joaquin Valley attainment status is unclassified. However, CURE made some attempt to establish the ambient H_2S air quality background (CURE 1999g). Three days of measurements resulted in two dissimilar average H_2S ambient air concentrations; 14 ug/m^3 (+/- 30.5%) and 33 ug/m^3 (+/- 85.9%), both values are below the state 1-hour standard of 42 ug/m^3. In addition, the field data indicates that wind conditions seem to play a large part in the H_2S ambient air concentrations, with calm winds allowing accumulation and producing higher concentration levels. Therefore, we would expect to see lower H_2S concentrations when unstable meteorological conditions exist. The overall range of values is 10.0 ug/m^3 to 61.4 ug/m^3.

CURE made an estimate of the H_2S emissions for the 700 new wells, at 42.2 tons/year (CURE 1999g). However, CURE did not apply the correct emission control factor for vapor recovery (99.9%). Also, CURE included emissions from storage tanks, which should be addressed in a cumulative impacts analysis. After applying the correct control factor to the 700 new wells and eliminating the storage tank emissions, staff determined that a conservative emission estimate is 4.4 tons/year. It should be noted that the H_2S concentrations in the vapor from a production well are very inconsistent from day to day and well to well, thus making an emission estimate very difficult and uncertain. A conservative modeling analysis of the original CURE emission factor (42.2 t/y) resulted in an impact of 29.7 ug/m^3 (CURE 1999g). Staff modified this impact to reflect the corrected emission rate (4.4 t/y). The corrected impact is 3.1 ug/m^3, approximately 7% of the state standard.

The District has been working with all the oil developers in the Western Kern County Oil Fields to reduce VOC (and thus H_2S) emissions. As an example, Texaco California Incorporated recently submitted an application for an Authority to Construct permit to the District for the installation of vapor recovery devices on existing oil extraction equipment. This application includes an estimate of VOC emission reductions of 5.3 tons/year, which represents an H_2S reduction of approximately 1.3 tons/year, based on the gas analysis provided in the application. While Staff is not suggesting that this reduction be used as mitigation for the H_2S emission increase, it is indicative of the efforts being taken to control H_2S emissions from wells and storage tanks in the area.

Because there is a lack of H_2S air quality data from the area, Staff cannot perform a standard air quality assessment. However, the relatively low impact from the estimated H_2S emissions suggests that a significant impact is unlikely. Given the low impact potential and the fact that the District (and oil producers) are addressing this issue, staff concludes that it is reasonable to expect that there will be no significant impact from H_2S emissions as a result of operating the 700 new wells.

WASTEWATER TREATMENT FACILITY EXPANSION

There are currently plans to expand the operations at the Valley WasteWater Treatment Facility due to oil field expansion. These plans are not definite at this time, and thus staff is not able to precisely evaluate the emissions or impacts associated with the expansion. However, it is known that the facility operators do not plan to expand past the current fence line of the existing wastewater treatment facility. The potential expansion could involve a significant amount of ground disturbance, which could have fugitive PM10 impacts as well as potential impacts from construction equipment exhaust. Current District rules provide effective mitigation for fugitive dust emissions (Rules 8010, 8020, 8030, 8060 and 8070). Operational emission increases will be mitigated through the District new source review rule 2201. Therefore, it is staff’s opinion that there is no reasonable expectation that the emissions, from both construction and operation associated with the expansion of the Valley WasteWater facility, will cause a significant air quality impact.

CUMULATIVE IMPACTS

Staff’s assessment of the cumulative impacts associated with the Sunrise project considers several elements in or near the proposed project site. Specifically, these elements will include the TCI Main Utility Corridor, the two other power plant projects in the western Kern County area (La Paloma Power Project and Elk Hills

Power Project), the expansion of the Midway-Sunset Oil Field and the formation of secondary pollutants (ozone and PM10).

TCI MAIN UTILITY CORRIDOR

The TCI Main Utility Corridor (TMUC) will provide the Sunrise project with natural gas, boiler water, feed water, and fresh water. TMUC will also accept steam and wastewater from the Sunrise project. The TMUC is intended to serve not only Sunrise, but also a significant number of field steam generators in the Texaco oil fields.

TMUC will tap the nearby Kern River Gas Transmission Company/Mojave Pipeline Company (KRGTC/MJP) gas transmission line. The project will replace an existing 12-inch diameter tap line with a 20-inch tap line. This line is 10,550 feet long and is buried 6 feet deep, necessitating the disturbance of 4,900 cubic yards of soil. The rest of the TMUC will be built on racks above ground. Therefore, very little soil disturbance will occur from the rest of the TMUC construction. As noted above, the TMUC will carry lines for fresh water, feed water, boiler water, steam, wastewater and natural gas. Additionally, the TMUC will carry along a small portion of its length the pumped oil/water line from the oil fields to the first stage of separation.

CONSTRUCTION

The construction of the TMUC has already begun, and is expected to be completed and fully operational by the time that this analysis is published. The majority of the construction emissions have already occurred and are therefore not addressed in this analysis. The only major construction element of the project yet to be completed is the replacement of the main tap to the KRGTC/MJP gas transmission pipeline. That element has been partially completed, but will be fully completed prior to any construction beginning on the Sunrise project. Therefore, staff does not include construction emissions associated with the TMUC in the cumulative impact analysis.

OPERATION

There are only minimal operational emissions from the TMUC. The project does not use any internal combustion engines or generators for any purpose. There are only small amounts of mobile emissions associate with standard operational and maintenance vehicles. Therefore, operational emissions associated with the TMUC are not considered in the cumulative impact analysis.

KERN COUNTY POWER PLANT PROJECTS

To evaluate reasonably foreseeable future projects as part of a cumulative impact analysis, staff needs specific information about the projects. The time in which a probable future project is well enough defined to have the information necessary to perform a modeling analysis is usually when the project owner has submitted an application to the District for a permit. Therefore, we evaluate those probable future projects in our cumulative impacts analysis that are currently under construction, or are currently under District review. Projects located up to six miles from the proposed facility site usually need to be included in the analysis. Staff performed an air dispersion modeling analysis that includes three proposed projects in the vicinity: the Sunrise project, the La Paloma Generating Project and the Elk Hills Power Project. Staff used the ISCST3 air dispersion model in its cumulative impacts analysis, along with the 1993 meteorological file provided by the La Paloma Power Project applicant. The results of this modeling analysis are shown in AIR QUALITY Table 15.

AIR QUALITY Table 15
Maximum Cumulative Impacts

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1-hour	25.31	94	119.3	470	25
	Annual	0.34	16.6	16.9	100	17
CO	1-hour	30.46	2941	2971.5	23,000	13
	8-hour	7.72	2222	2229.7	10,000	22
SO_2	24-hour	0.12	20	20.1	130	15
	Annual	0.02	1.8	1.8	80	2
PM10	24-hour	1.12	118	119.1	50	238
	Annual	0.17	31.7	31.9	30	106

As the data in AIR QUALITY Table 15 show, the cumulative air quality effects of the three projects, La Paloma, Elk Hills and Sunrise, do not cause a new violation of any NO_2, CO or SO_2 ambient air quality standards. The three projects would contribute to already existing violations of the state PM10 ambient air quality standards. However, all three of these projects will be required to provide PM10 emission offsets to mitigate their PM10 impacts. A more detailed discussion of this modeling analysis is provided in Appendix A.

MIDWAY-SUNSET OIL FIELD EXPANSION

The Sunrise project will be located in the Midway-Sunset oil field and will supply steam to oil wells within a ¾ mile radius of the power plant site. The total estimated number of wells served by the Sunrise project is approximately 2,000, of which 700 will be new. The air quality implications of those 700 new wells have already been discussed previously in this analysis. However, there are many other operators in the Midway-Sunset oil fields (other than Texaco), some of whom plan to expand their operations. As discussed previously, any significant expansion in the oil well field is regulated by the District under their New Source Review rules (specifically Rule 2201). Under this rule, a new well must include a vapor recovery system to control VOC emission to 99.9% effectiveness. Furthermore, any new (or modified) storage tank must also be equipped with vapor control. These vapors may not be vented to the atmosphere, but must be combusted, typically through field steam generators or in some cases, flares. These combustion sources also fall under the District regulations and have limits on their emissions.

There are some case where new, vapor controlled wells are connected to existing, non-controlled storage tanks. In these cases, the operators are some times allowed to “shut in” the well vapors which may provide a significant control or they are allowed to vent these vapors through the storage tanks. There are conditions and limits on this activity, the District strongly discourages it and it does tend to limit the productivity of the wells. The 2000 wells that Sunrise will be serving are not expected to use this technique[11]. It is reasonable to expect that the Texaco Heavy Oil Fields operations in Midway-Sunset will convert most of the uncontrolled storage tanks to vapor control so that they may increase production in the area without having to risk a notice of violation. Since this trend is occurring, and is encouraged by the District, staff concludes that there is every reasonable expectation to assume that there will be no significant air quality impact from further oil field exploration.

SECONDARY POLLUTANT IMPACTS

The project’s gaseous emissions, NO_x, SO_2, VOC and ammonia can contribute to the formation of ozone and secondary PM10.

OZONE

There are air dispersion models that can be used to quantify ozone impacts, but they are used for state implementation planning efforts (typically at the air district level) where hundreds or even thousands of sources are input into the model to determine ozone impacts. There are no regulatory models approved for assessing single source emissions for ozone impacts. However, because of the known relationship of NO_x and VOC emissions to ozone formation, it can be said that these emissions from the Sunrise project do have the potential to contribute to higher ozone levels in the region. While this potential can not be quantified, it can be conservatively characterized as significant if left unmitigated.

Emissions from the San Joaquin Valley Air Basin are considered a significant contributor to the ozone exceedences in the South Central Coast Air Basin (SCCAB) (ARB 1996). That is, air pollution from the San Joaquin Valley in combination with emissions from within the SCCAB do cause violations of ozone ambient air quality standards within the SCCCB. However, ARB has found that San Joaquin Valley emissions alone do not cause violations of ozone standards within the SCCAB. To reduce ozone precursor (NO_x and VOC) emissions within their own District as well as reducing the impact to neighboring air basins, the San Joaquin Valley Unified Air Pollution Control District has adopted best available retrofit control technology (BARCT) (ARB 1996) to a number of categories of stationary sources. The Sunrise project’s operational emissions will be offset and thus there will be no net emissions increase. Therefore, staff believes that there will be no significant impact, either within the San Joaquin Valley Air Basin or in the neighboring SCCAB. The construction impacts are very short term and are not likely to contribute to significant ozone formation in the SCCAB. Therefore, it is staff’s opinion that there will be no significant impacts from either the project’s direct or indirect emissions on the formation of ozone in the South Central Coast Air Basin.

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[1] Public conversation with Texaco California Incorporate employee during the Biology workshop at the California Energy Commission on Thursday October 28, 1999.

SECONDARY PM10

Concerning secondary PM10 (primarily ammonium nitrate but also ammonium sulfate) formation, the applicant for the La Paloma Project (LPPP 1999a) submitted a conclusion from a study by Sonoma Technology, Inc. which states that the San Joaquin Valley is generally ammonia rich during the winter season when ambient PM10 levels are highest. This means that under such conditions, adding more ammonia to the ambient air will not automatically result in more ammonium nitrate formation.

SCPC has committed to an ammonia slip no greater than 10 ppm, which is the current ammonia slip level being permitted throughout California. On a daily basis, the ammonia slip of 10 ppm is equivalent to approximately 1,166 lb./day of ammonia emitted into the atmosphere. However, the assumption that the ammonia slip is routinely at 10 ppm is incorrect. That level of ammonia emission is usually associated with the degradation of the SCR catalyst, usually in a time frame of five years or more after initial operation. At that point, the SCR catalysts are removed and replaced with new catalysts. Through most of the operation of the SCR system, ammonia slip emissions are usually in the range of 1 to 2 ppm, corresponding to a mass emissions of approximately 100 to 250 pounds per day. There is currently no accepted model to predict the impact on ammonium nitrate formation from a single ammonia emission source. Given this information, staff concludes that there is very little potential for any ambient air impacts from the Sunrise project ammonia emissions.

However, the NO_x and SO_x emissions from the Sunrise project could add to ammonium nitrate and ammonium sulfate (PM10) formation, since there is more than sufficient ambient ammonia available for the NO_x or SO_x to react with and form PM10. The process of gas-to-particulate conversion is complex and depends on many factors, including local humidity and the presence of other compounds. Currently, there is no agency (EPA or CARB) recommended models or procedures for estimating nitrate or sulfate formation from single source emissions. Nevertheless, studies during the past two decades have provided data on the oxidation rates of SO_2 and NO_x. The data from these studies can be used to approximate the conversion of SO_2 and NO_x to particulate. This can be done by using an aggregate conversion factor (typically about 0.01 to 1 percent per hour) with Gaussian dispersion models such as ISCST3. The model is run with and without chemical conversion (decay factor) and the difference corresponds to the amount of SO_2 and NO_2 that is converted to particulate. This approach is an over simplification of a complex process; nevertheless, given the stringency of the PM10 and the new potential PM2.5 standards, staff believes this issue needs to be addressed.

Staff, as part of their cumulative modeling analysis, quantified the potential secondary PM10 impacts from the three power projects in the area currently before the Commission for licensing: La Paloma, Sunrise and Elk Hills. For NO_x to nitrate formation, staff assumed a conversion rate of 33% over a time span of 18 to 24 hours. For oxides of sulfur to sulfate formation, staff assumed a conversion rate of 50% over 8 hours. These conversion rates can be input into the ISCST3 model to predict possible nitrate and sulfate PM10 impacts. The combined three-project nitrate impact was predicted to be approximately 1µg/m^3, located about 50 miles to the northeast of the projects' sites. The combined sulfate impacts would be approximately 0.1µg/m^3, located about 30 miles to the northeast. For a more complete discussion of the cumulative modeling analysis, please refer to Appendix A. Based on these results Staff concludes that the Sunrise project NO_x and SO_x emissions do have the potential to contribute to secondary PM10 levels in the region if left unmitigated.

MITIGATION

SCPC'S PROPOSED MITIGATION

CONSTRUCTION MITIGATION

As discussed earlier in the applicable LORS section, there are a series of District rules under Regulation 8 that limit fugitive dust during the construction phase of a project. Those rules require the use of chemical stabilizing agents and dust suppressants or gravel areas on site, and the wetting or covering of stored earth materials on site. They also encourage, although do not require, the use of paved access aprons, gravel strips, wheel washing or other means to limit mud or dirt carryout onto paved public roads. Because they are required by District rules, SCPC will employ appropriate fugitive dust mitigation measures to limit their construction related PM10 emissions.

OPERATIONS MITIGATION

The Sunrise project's air pollutant emissions impacts will be reduced by using emission control equipment on the project and by providing emission offsets. To reduce NO_x emissions, SCPC proposes to use dry-low NO_x combustors in the CTGs. In addition, an ammonia injection grid will be used in conjunction with a Selective Catalytic Reduction system.

To reduce CO and VOC emissions, SCPC proposes to use good combustion and maintenance practices. PM10 emissions will be limited by the use of a clean burning fuel (natural gas) and the efficient combustion process of the CTGs. The use of natural gas as the only fuel will limit SO_2 emissions.

COMBUSTION TURBINE

Dry Low-NO_x Combustors

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NO_x formed during combustion. Because of the expense and efficiency losses due to steam or water injection in the combustor cans to reduce combustion temperatures and the formation of NO_x, CTG manufacturers are presently choosing to limit NO_x formation through the use of dry low-NO_x technologies. The GE version of the dry low-NO_x combustor is a four-stage ignition system. Initially the fuel/air mixture is ignited in two independent combustors (0% to

35% load). Then the startup sequence moves to a lean-lean operation (35% to 70% load) where the center burner is engaged as well. Then second stage burning is begun and all the fuel is directed to the center burner. The second stage burning is a transient event while proceeding to the premixed phase. Premixed operation (70% and 100% load) has fuel being pumped to all burners, but ignition only in the center burner.

In this process, firing temperatures remain somewhat low, thus minimizing NO_x formation, while thermal efficiencies remain high. At steady state CTG loads greater than 40 percent, NO_x concentrations entering the HRSG are 25 ppm corrected to 15 percent O_2. CO concentrations are more variable, with concentrations greater than 100 ppm at 50 percent load, dropping to 5 ppm at 100 percent load.

Selective Catalytic Reduction (SCR)

SCPC is proposing to use selective catalytic reduction to control NO_x emissions from the HRSG. Selective catalytic reduction refers to a process that chemically reduces NO_x by injecting ammonia into the flue gas stream over a catalyst in the presence of oxygen. The process is termed selective because the ammonia reducing agent preferentially reacts with NO_x rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs.

Flue gas temperatures from a combustion turbine typically range from 950 to 1100^{o}F. Catalysts generally operate between 600 to 750^{o}F (ARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600^{o}F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800^{o}F, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770^{o}F (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NO_x to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.

EMISSION OFFSETS

District Rule 2102, Section 4.2, requires that SCPC provide emission offsets, in the form of banked Emission Reduction Credits (ERC), for the project's emissions increases of NO_x, SO_2, VOC and PM10. Offsets for the project's CO emissions are not required since the project will not cause any violations of any CO standard and the area currently does not experience any violations of any CO standard.

SCPC has submitted several ERC certificates to offset the project's emissions Because of the difference in opinion between the staff and the District staff on the startup scenarios discussed earlier in our analysis, there is a difference in the annual emissions from the project and thus the amount of emission offsets that need to be secured. In staffs opinion, either further ERCs are necessary or the Sunrise project will have to accept stricter operating conditions. If revised emission limits, particularly as they pertain to startup and shutdown can be changed, then further offsets may not be necessary. These issues regarding startup/shutdown, the annual emissions liability and the amount of offsets are still unresolved and prevent staff from making any conclusions regarding the project's compliance with the District's rules and regulations. AIR QUALITY Table 16 shows the SCPP offset liability and their NSR liability. The NSR liability is a fairly complex assessment of Texaco Oil Field operations. Simply put, there is an outstanding existing emission liability for PM10 that, according to District rules, Sunrise is now obligated to offset as part of their project. The Project's daily emissions shown in AIR QUALITY Table 16 represent the project operating at 100% load at 65^{o}F for the entire day, which is the most likely operation of the SCPP. The ERCs daily averages are calculated from the annual values.

AIR QUALITY Table 16
Offset Liability and Emission Reduction Credit Balance

	Offset Liability (tons/yr)	NSR Liability (tons/yr)	Emission Reduction Credits By Distance Ratio Applied (ton/yr)				Project Emissions not Offset (tons/yr)	Project Daily Emissions (lbs/day)	ERC Average Daily Offset[a] (lbs/day)	Daily Project Emission Excedences (lbs/day)
			1.0 to1	1.2 to 1	1.5 to 1	Total ERC Values				
NO_x	137.9	--	--	64.4	123	135.71	2.15	739	1,026	-287
SO_2	28.8	--	28.5	--	--	28.54	0.26	158	156	2
VOC	24.9	--	--	28.3	--	23.57	1.33	125	155	-30
PM10	79.3	10.7	33.1	--	84.9	89.68	0.32	432	647	-215

[a] The ERC Average Daily Offsets are calculated by summing the annual ERCs without considering the distance ratio normal apply by the District, then dividing by 365.

The SCPP daily emissions are all completely offset by the ERCs provided with the exception of SO_2, which exceeds the ERCs provided by 2 lbs/day. However, for PM10 there is a net emissions reduction of 215 lbs/day. Since SO_2 is a precursor to secondary PM10 formation, staff concludes that the slight increase in SO_2 emissions will be more than compensated by the larger net emissions reduction of PM10. Therefore, it is staff's opinion that the project impacts on the short term ambient air quality standards in completely offset by the ERCs proposed.

ADEQUACY OF PROPOSED MITIGATION

CONSTRUCTION MITIGATION

SCPC is required to comply with District Regulation 8 for limiting fugitive dust emissions during project construction. Staff believes that additional measures are necessary to adequately mitigate potential construction impacts (refer to staff proposed mitigation below).

OPERATIONS MITIGATION

EMISSION CONTROLS

SCPC has proposed, in their opinion, all practical and technically feasible mitigation measures to limit NO_x emissions from the GE combustion turbines to 2.5 ppm over a 1-hour average. This level of control is defined as Best Available Control Technology by the District and is consistent with USEPA recommendations for BACT. Staff finds that this level of control is adequate for the proposed project.

OFFSETS

Because of the difference in opinion between the staff and the District staff on the amount of offsets that need to be provided for the project, all of the project's emissions and subsequent impacts from those emissions are not fully mitigated. However, staff intends to work with the District and all other parties to the extent possible to come to a resolution of this issue.

STAFF PROPOSED MITIGATION

CONSTRUCTION MITIGATION

As stated above, there are a number of rules in the District's Regulation 8 that will minimize fugitive dust emissions. Those rules allow for some latitude and flexibility as to how they will demonstrate compliance. In general, SCPC will be required to control fugitive dust emissions to the extent feasible.

The modeling assessment discussed earlier shows that the combustion sources used for heavy construction have the potential for causing significant air quality impacts. SCPP is not proposing to minimize combustion emissions such as NOx, CO, VOC and PM10. Control of combustion emissions associated with construction is not required by District rules. However, staff has become recently aware of an exhaust catalyst device that is available and cost effective which controls combustion emissions from construction equipment. The catalyst is a post combustion soot filter and oxidation device that replaces the muffler of the construction equipment. It reduces CO and hydrocarbon (VOC) emissions by approximately 80-90% and PM10 emissions by approximately 90-99%. This technology has been in the market for approximately 10 years and is available from several companies. The Cinco Group offers the DPX Catalyst installed at approximately $8,000 each. Under SCPC's current construction plan of using approximately 25 different pieces of heavy duty construction equipment, the cost of these catalysts would be approximately $200,000.

OPERATIONS MITIGATION

The SCPP's net daily emissions (project emissions minus the emission offsets provided) result in an overall emissions reduction in the San Joaquin Valley (see AIR QUALITY Table 16). Staff's emphasis on the net daily emissions is to assess the SCPP's potential impacts on the 24-hour PM10 and 1-hour Ozone ambient air quality standards. Therefore, it is staff's opinion that the SCPP's potential impacts is fully mitigated. However, it is staff's opinion that SCPP does not fully comply with the District rules and regulations, specifically the New Source Review Rule 2201. Staff believes that the District made an erroneous assumption about the time it will take for the project to startup and as a result, they have under estimated the SCPP offset liability (see the discussion below in the Staff Evaluation of Local and Federal Permits section for more details). This issue is unresolved at this time.

INDIRECT PROJECT IMPACT MITIGATION

Staff finds that any potential impacts from indirect emissions in the oil field are adequately addressed by the District and require no further mitigation measures.

STAFF EVALUATION OF LOCAL AND FEDERAL PERMITS

Staff relies on the local air district to evaluate the proposed project for compliance with their rules and regulations, which is the Determination of Compliance (DOC). Also, the US EPA must issue a Prevention of Significant Deterioration (PSD) permit showing that the proposed project meets the PSD requirements. Both of these analyses (the DOC and the PSD) include permit conditions for the project. In reviewing the District's Final DOC (SJVUAPCD 1999h) and EPA's draft PSD (USEPA 1999b) permit conditions, staff has noticed that certain permit conditions in both documents appear to contradict each other. To complicate matters further, CURE has filed a request for a hearing at the District in an effort to block the Final DOC as issued (CURE 1999h). In this section staff will identify the issues raised in the DOC, the PSD analysis and by CURE, and discuss the staff position.

ISSUES RAISED BY CURE

THE NOTICE OF VIOLATION ISSUE

CURE contends that the current DOC violates Rule 2201 section 4.3.3 and section 5.2.5 as they pertain to the existence of outstanding Notice of Violations (NOVs) issued against Texaco (parent company to Sunrise) (CURE 1999h). These NOVs were identified during the comment period of the Preliminary Determination of Compliance (PDOC). The Final Determination of Compliance (FDOC) was issued with the condition that Texaco resolve all outstanding NOVs. CUREs second issue is that the District cannot issue a FDOC with the NOV issue not resolved (CURE 1999h). A letter was issued by the District on December 2, 1999 (after the FDOC was issued) stating that these NOVs have been resolved to the satisfaction of the District Air Pollution Control Officer (APCO). While the District issued a conditional FDOC, it has since resolved that conditional status. Therefore it is staff's opinion that the District has issued a valid FDOC and that the NOVs in question have been adequately resolved.

TIMELY ISSUANCE OF THE FDOC

CURE contends that the District missed their statutory cut-off date to issue a final opinion on the Sunrise application (CURE 1999h). The District had issued a letter dated October 5, 1999 notifying Sunrise that their application was no longer being considered "complete" due to the outstanding NOVs issued against Texaco. However, the District stated that it would continue with the PDOC and FDOC process at that time expecting Texaco to resolve the NOVs soon. It is the District's opinion that its letter effectively reset the clock on October 5. Staff has no opinion on whether the clock is reset or not, and since the District issued its FDOC staff can see no issue here.

NO_x AND CO POTENTIAL TO EMIT CALCULATIONS

CURE contends that the District did not correctly calculate the potential to emit and thus underestimates the offset liability (CURE 1999h). Staff has reviewed both the draft PSD (USEPA 1999b) and FDOC (SJVUAPCD 1999h) to determine the positions taken by EPA and the District respectively. First, both EPA and the District are assuming 20 startups and 20 shutdowns per turbine per year. The applicant requested and then rescinded a request that the number of start up and shutdowns be increased from 20 to 100 per year for each turbine. The District is assuming a 20-minute duration for each startup/shutdown event to calculate the emission liability, while allowing the applicant to emit at start up emission levels for 60 minutes. EPA requires that the turbines start up in no more than 20 minutes and has placed an hourly emission limit consistent with a 20-minute start up and 40-minute operation at 100% load. Staff's position is that neither one of these approaches is correct and workable for the applicant. Staff is concerned that the applicant will not be able to start up the turbine in 20 minutes every time and that there are consequences if they do not (i.e., NOVs). Staff is also concerned that the estimated startup emissions are not being offset by the District analysis. This issue is complicated by the fact that each agency involved (as well as CURE) has made a different assumption regarding both startup and normal operation. In the next few tables, staff presents the various assumptions that have been made to calculate the potential to emit for the project. It is safe to assume that SCPC's position is identical to that of the District's because they have been working closely with the District to generate the FDOC. In AIR QUALITY Table 17, staff presents the startup/shutdown assumptions made. In their Request for Hearing, it is evident that CURE (as well as the CEC) did not discover that Sunrise had withdrawn their request to have 100 startups and 100 shutdowns per turbine. The two basic positions are whether the turbines will have 20 minutes or an hour to start up.

AIR QUALITY Table 17
Assumed Startup and Shutdown Event Emissions

	Number of Events per year per Turbine	Event Duration (minutes)	Estimated Emissions per Event per Turbine (lbs/hr)	
			NO_x	CO
EPA, Draft PSD	40	20	32	163
District, Final DOC	40	20	32	163
CURE, Hearing Request	200	60	96	489
Staff, FSA	40	60	96	489

The District, in their FDOC condition 13, restricts the duration of a startup and shutdown to one hour. Condition 14 restricts the emissions during this period from both turbines to 112.5 lbs of NO_x and 513.1 lbs CO. These conditions are consistent with the assumption that startup emissions for one turbine are 96 lbs of NO_x and 489 lbs of CO with the other turbine operating at full load (16.5 lbs of NO_x and 24.1 lbs of CO). However, the NO_x offset quantities were calculated based on a 20-minute startup/shutdown (32 lbs of NO_x) and 40 minutes of steady state operation (10.3 lbs of NO_x). What this effectively does is allow SCPP to emit 96 lbs of NO_x per startup/shutdown per turbine but only mitigate 42.3 lbs, leaving the remaining 53.7 lbs of NO_x unmitigated.

There are further differences in the way the operational emissions where handled that tend to complicate this issue. In AIR QUALITY Table 18, staff presents the various assumptions made for operational emissions. The CO emission limit used by EPA is a value that was originally submitted in the Sunrise Application for PSD and no longer reflects the current hourly emission estimates at 6 ppm for CO. AIR QUALITY Table 18 shows that the main area of contention is the expected hours of operation at full load. EPA and the District assume that 8746 2/3 hours of operation are available because they also assume that the startups and shutdowns only last 20 minutes. Staff's position is that the startups and shutdowns last 60 minutes and thus only 8720 hours are available for steady state operation. CURE was not aware of the change back to 20 startup and 20 shutdowns prior to their filing the Request for Hearing with the District. Therefore, the 8560 hours CURE used in their calculations reflects 200 startups and shutdowns, which is not currently proposed for the project.

AIR QUALITY Table 18
Assumed Emissions for Normal Operation of one Turbine

	Hours of Operation at Full Load	NO_x Emission (lbs/hr)	CO Emission (lbs/hr)
EPA, Draft PSD	8746 2/3	15.4	19.4[a]
District, Final DOC	8746 2/3	15.4	22.5
CURE, Hearing Request	8560	15.4	22.5
Staff, FSA	8720	15.4	22.5
[a] This may be a value from an earlier filing by the applicant, which was revised.			

AIR QUALITY Table 19 shows the cascading impact that all these various assumptions have on the final potential to emit value. It is important to remember that CURE is assuming there are 200 startup and shutdowns per turbine, when in reality Sunrise has requested only 40. Other than that assumption, the CURE and Staff assumptions agree. The only significant difference left then in this issue is between the staff assumptions and the District assumptions. Those differences hinge on the duration of startup/shutdown events. The District assumes they are 20 minutes in duration, but allows an hour, while staff assumes an hour in duration and believes that this one-hour duration should be appropriately mitigated. With the staff assumptions, Sunrise would be required to provide additional offsets for 2.15 tons of NO_x liability. CO offsets are not required for this project.

AIR QUALITY Table 19
Annual Emissions based on Assumption made
(tons/year)

	Start up		Full Load		Total per Turbine		**Total Both Turbines**	
	NO_x	CO	NO_x	CO	NO_x	CO	**NO_x**	**CO**
EPA, Draft PSD	0.64	3.26	67.21	84.84	67.85	88.1	**135.7**	**176.2**
District, Final DOC	0.64	3.26	67.21	98.48	67.85	101.7	**135.7**	**203.5**
CURE, Hearing Request	9.60	48.90	65.78	96.38	75.38	145.3	**150.8**	**290.6**
Staff, FSA	1.92	9.78	67.14	98.1	69.06	107.9	**137.9**	**215.8**

VOC AND PM10 POTENTIAL TO EMIT CALCULATIONS

A similar argument can be made for the VOC and PM10 potential to emit calculations in the District FDOC. The differences in opinion revolve around the startup/shutdown duration. The District and EPA have assumed 20 minutes, while the staff has assumed an hour. In this case, if the staff assumptions where used, Sunrise would need additional offsets for 0.32 ton of PM10 and 1.33 tons of VOC emission liabilities.

The issues regarding startup assumptions were identified and discussed in the PDOC/PSA workshop on August 16, 1999 in Kern County. However, no specific written comments from any party were made regarding the “potential to emit” calculation and the “startup duration.”

AMMONIA SLIP LEVEL

CURE contends in the Request for Hearing that the BACT determination for NO_x is faulty because it did not include an ammonia slip limit of 5ppm. Instead, the District evaluation concluded that a 10ppm limit was satisfactory. CURE also asserts that the District should have required a CO catalyst for the BACT determination of CO and VOC emissions. The BACT level requirement for NO_x is currently 2.5 ppm averaged over 1-hour. BACT for NO_x is not technology specific and it does not include a recommendation for ammonia slip levels. The California Air Resources Board specified in their guidance document a recommendation of below 5 ppm for ammonia slip. However, this is a recommendation and not a requirement, therefore air districts are allowed latitude in setting ammonia slip permit levels. The BACT level for CO is a level, not a technology. Therefore, a CO catalyst is not required as long as Sunrise can meet the BACT CO emission concentrations without one.

The BACT determination for VOC was also raised as an issue by CURE, as they believe that BACT should be 0.6 ppm or lower. The CARB guidelines recommend a BACT level of 2.0 ppm. The District has determined BACT for VOC at 1.2ppm and has required Sunrise provide offsets accordingly. Staff does not see this as a significant issue because of the relative mass emissions involved. The VOC mass emission at 0.7 ppm for La Paloma is 2.59 lbs/hr, while the VOC mass emission at 1.2 ppm for Sunrise is 2.62 lbs/hr, that is roughly a difference of 0.03 lbs/hr and it will be fully mitigated.

PM10 EMISSION LEVEL

CURE asserts that the District incorrectly allowed the PM10 emissions to be permitted at 9 lbs/hr. CURE cites a document that they provided during the comment period of the PDOC. That document was intended to illustrate that the SCPP could not achieve 9 lbs/hr of PM10. The District and the CEC reviewed the document and found no compelling argument to support this claim. There are two parts to PM10, the filterable (front half) and the condensable (back half). Staff found that the summary of PM10 source tests, provided by CURE, demonstrated that the condensable fraction is in many cases as high as the filterable fraction, particularly for combustion turbines in the southern San Joaquin Valley. However, the only power plant close in size and configuration to the SCPP is the Crockett Cogeneration Project, located in the Bay Area. In 1998, the Crockett Power Plant recorded filterable PM10 at 2.82 lbs/hr. Earlier source tests in 1996 and 1997 showed PM10 emissions at less than 2.3 lbs/hr. Based on these measurements and the data from other smaller combustion turbines, staff is comfortable in an emission limit of 9 lbs/hr for PM10 for the SCPP. The District is requiring that SCPP source test for PM10 (front and back half) twice during the first year of operation, once during the summer and once during the winter. The District and staff agree that this will insure, along with subsequent annual source tests, that the PM10 limit is maintained.

ERC ISSUE

CURE is questioning the validity of the emission reduction credits supplied to offset the project impacts. The issue is whether these ERCs are surplus and if RACT adjustments will apply. EPA has also expressed continuing concerns over the use of ERCs without the appropriate tracking system in place. Staff has no authority in this area, and thus will render no opinion but to express concern at the continuing debate between the District and EPA.

DETERMINATION OF COMPLIANCE

Staff has reviewed the final determination of compliance (FDOC) issued by the District and determined that FDOC conditions 14, 17 and 20 may significantly change as a result of the Request for Hearing filed by CURE. Condition 14 contains hourly emission rates and duration limits. Condition 17 contains the annual emission limits, and condition 20 contains the quarterly level of offsets required to mitigate the project emissions.

EPA PREVENTION OF SIGNIFICANT DETERIORATION

Under the special conditions section X, letter C item 2 (USEPA 1999b). EPA is restricting the Sunrise applicant to 20-minute startup/shutdown duration. It is staff's opinion that this is too strict and should be increased to 1-hour. Letter E, item 1 and 2, the CO emission limits are not consistent with the project as currently proposed. The same can be said for Letter F, item 2, the NO_x emission limit during startup.

COMPLIANCE WITH LORS

FEDERAL

The SCPC is currently under review by EPA on the Prevention of Significant Deterioration (PSD) permit. EPA has issued a draft PSD analysis, for which the comment period closed December 13, 1999.

STATE

The project, with the anticipated full mitigation (offsets) that will be necessary for the project to secure a Determination of Compliance from the SJVUAPCD, should comply with Section 41700 of the California State Health and Safety Code. Additional offsets may be required beyond that currently identified in the Determination of Compliance. Assuming the annual emission liability and offset issue is successfully resolved, the project would thus be fully mitigated and therefore would not cause any injury, detriment, nuisance or annoyance to the public.

LOCAL

Compliance with specific SJVUAPCD rules and regulations are discussed below. For a more detailed discussion of the compliance of the SCPP, please refer to the Determination of Compliance (SJVUAPCD 1999h).

RULE 2201 - NEW AND MODIFIED STATIONARY SOURCE REVIEW RULE

SECTION 4.1 - BEST AVAILABLE CONTROL TECHNOLOGY

The SJVUAPCD has determined the Best Available Control Technology for the emission generating equipment and is summarized in the following AIR QUALITY Table 20.

AIR QUALITY Table 20
BACT Determinations

Pollutant	Gas Turbine Engines
PM10	Air inlet filters, lube oil vent coalescer and opacity <5%, natural gas fuel
SO_2	Utility quality natural gas
NO_x	2.5 ppm @ 15% O_2, 1-hr average
VOC	1.2 ppm @ 15% O_2 3-hr average
CO	6 ppm @ 15% O_2 3-hr average

SECTION 4.2 - OFFSETS

SCPC demonstrated through air dispersion modeling that their project would not cause a violation of any CO ambient air quality standard, therefore CO emission offsets are not required for the combustion turbine CO emissions. All other project emissions are subject to emissions offsets, which are discussed in the Mitigation section of this analysis, and in greater detail in the DOC. As discussed earlier, staff does not believe that the District has accurately calculated the project's potential to emit, and thus the amount of offsets for the project. Therefore, staff does not believe that the project complies with Section 4.2 of the District's regulations.

SECTION 4.3 - ADDITIONAL SOURCE REQUIREMENTS

Rule 4.3.2.1 requires that a new source not cause, or make worse, the violation of an ambient air quality standard as demonstrated through analysis with air dispersion models. Because the project demonstrates that it does not cause a violation of any CO ambient air quality standard, and that the project is fully offset for its other emissions, the District has determined that the SCPP will not make the ambient air quality worse. However, staff disagrees with the District assessment and recommend either further offsets be provided or that SCPP be further constrained during startup/shutdown procedures.

Rule 2520 – Federally Mandated Operating Permits

SCPC is required to file a Title V Operating permit with the District within 12 months of commencing operation. Presently, no action is required.

Rule 2540 – Acid Rain Program

An acid rain application must be submitted at least 24 months prior to the project generating electricity and was submitted in July 1999. The requirements will include that NO_x and SO_x emissions will have to be monitored and a small quantity of SO_x allowance will have to be provided from a national SO_x allowance bank. Compliance will be determined at a later date.

Rule 4001 - New Source Performance Standards

Based on the heat rate of the GE Frame 7FA turbine, a NSPS NO_x limit is calculated at 109 ppmv at 15% O_2. The SCPP will be permitted at 2.5 ppmv at 15% O_2. The SO_x emission concentration will be 0.38 ppmv at 15% O_2 which is less than the NSPS requirement of 150 ppmv. The sulfur content of the natural gas fuel is equivalent to 0.003% which is less than the NSPS requirement of 0.8%. Compliance with Rule 4001 is therefore demonstrated.

Rule 4101 - Visible Emissions

All equipment will be limited to a 5 percent opacity limit by permit condition, which is less than the rule requirement of 20 percent opacity.

Rule 4201 - Particulate Matter Concentration

The District determined that the particulate emissions from the GE Turbines at 60% load, 115^{o}F ambient air temperature is 0.0022 gr/dscf. This emission rate is below the rule limit of 0.1 gr/dscf, therefore compliance is demonstrated.

Rule 4703 - Stationary Gas Turbines

The permitted NO_x limit of 2.5 ppm is below the rule mandated limits of 9 ppm for SCR controlled turbines. The permitted CO limit of 6 ppm is well below the rule requirement of 25 ppm.

Rule 4801 - SO_2 Concentration

The fuel sulfur content of the natural gas to be used at the SCPP will result in a SO_2 emission concentration of 0.38 ppm @ 15% O_2 and is not expected to exceed the 2,000 ppm limit imposed by this rule.

Rule 8010 - Fugitive Dust Administrative Requirements for Control of Fine Particulate Matter (PM-10)

SCPC will provide a Construction Fugitive Dust Mitigation Plan that will discuss the types of chemical stabilizing agents and dust suppressant materials they intend to use.

Rule 8020 - Fugitive Dust Requirements for Control of Fine Particulate Matter (PM-10) from Construction, Demolition, Excavation, and Extraction Activities

The Construction Fugitive Dust Mitigation Plan will specify the specific measures that SCPC will employ to limit fugitive dust and thus comply with this rule.

Rule 8030 - Control of PM10 from Handling and Storage of Bulk Materials

The Construction Fugitive Dust Mitigation Plan will specify the specific measures that SCPC will employ to limit fugitive dust during the handling and transport of any borrow soil if needed and thus comply with this rule.

Rule 8060 - Control of PM10 from Paved and Unpaved Roads

The Construction Fugitive Dust Mitigation Plan will specify the use of chemical dust suppressant and/or the use of paved shoulders on paved roadways that will demonstrate compliance with this rule.

Rule 8070 - Control of PM10 from Vehicle/Equipment Parking, Shipping, Receiving, Transfer, Fueling and Service Areas

The Construction Fugitive Dust Mitigation Plan will include measures to limit fugitive dust from unpaved parking areas and the tracking out of mud and dirt onto public roadways, and thus demonstrate compliance with this rule.

CONCLUSIONS AND RECOMMENDATIONS

The Sunrise project’s potential air quality impacts with the construction mitigation proposed by staff, would all be mitigated to a level of insignificance.

At present, the Determination of Compliance issued by the District is in staff’s opinion, not in conformance with the District’s rules, specifically Rule 2201, Section 4.2. Therefore, staff at this time cannot recommend approval of the Sunrise Cogeneration and Power Project. However, presuming that the issue of conformance with the District’s rules can be resolved, staff is proposing the following Conditions of Certification, which includes staff’s proposed conditions. Nevertheless, staff is not recommending Conditions AQ-17 and AQ-18 be adopted until the conformance with Rule 2201, Section 4.2 issue is resolved.

CONDITIONS OF CERTIFICATION

AQ-C1 Prior to the commencement of project construction, the project owner shall prepare a Construction Fugitive Dust Mitigation Plan that will specifically identify fugitive dust mitigation measures that will be employed for the construction of the Sunrise project.

a) The Construction Fugitive Dust Mitigation Plan shall specifically identify measures to limit fugitive dust emissions from construction of the project site. Measures that should be addressed include the following:

- the identification of the employee parking area(s) and surface of the parking area(s);
- the frequency of watering of unpaved roads and disturbed areas;
- the application of chemical dust suppressants;
- the stabilization of storage piles and disturbed areas;
- the use of gravel in high traffic areas;
- the use of paved access aprons;
- the use of posted speed limit signs;

- the use of wheel washing areas prior to large trucks leaving the project site; and,
- the methods that will be used to clean tracked-out mud and dirt from the project site onto public roads.

b) The following measures should be addressed for the transportation of the borrow fill material to the Sunrise project if any borrow is transported from offsite: the use of covers on the vehicles, the wetting of the material and insuring appropriate freeboard of material in the vehicles.

Verification: Sixty (60) days prior to the start of construction, the project owner shall provide the CPM with a copy of the Construction Fugitive Dust Mitigation Plan for approval.

AQ-C2 The project owner shall require as a condition of its construction contracts that all contractors/subcontractors ensure that all heavy earthmoving equipment, that includes bulldozers, backhoes, compactors, loaders, motor graders and trenchers, and cranes, dump trucks and other heavy duty construction related trucks, have been properly maintained and the engines tuned to the engine manufacturer's specifications and that oxidizing soot filters have been installed and are functioning properly.

Verification: The project owner shall submit to the CPM, via the Monthly Compliance Report, documentation, which demonstrates that the contractor's/subcontractor's heavy earthmoving equipment is properly maintained and the engines are tuned to the manufacturer's specifications. The project owner shall submit, via the Monthly Compliance Report, documentation which demonstrates that the contractor/subcontractor have acquired and installed oxidizing-soot-filters for all heavy earthmoving equipment. The project owner shall maintain construction contracts on the site for six months following the start of commercial operation.

SJVUAPCD Permit No. S-3492-1-0: 165 MW NOMINALLY RATED COGENERATION SYSTEM #1 INCLUDING GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR W/ DRY LOW-NO_XCOMBUSTORS, UNFIRED HEAT RECOVERY STEAM GENERATOR (HRSG), SELECTIVE CATALYTIC REDUCTION, AND OXIDATION CATALYST IF NECESSARY.

SJVUAPCD Permit No. S-3492-2-0: 165 MW NOMINALLY RATED COGENERATION SYSTEM #2 INCLUDING GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR W/ DRY LOW-NO_XCOMBUSTORS, UNFIRED HEAT RECOVERY STEAM GENERATOR (HRSG), SELECTIVE CATALYTIC REDUCTION, AND OXIDATION CATALYST IF NECESSARY.

AQ-1 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, California Air Resources Board (CARB) and the Commission.

AQ-2 The project owner shall submit selective catalytic reduction, oxidation catalyst (if to be installed), and continuous emission monitor design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

<u>Verification:</u> The project owner shall provide copies of the design drawings of the catalyst system chosen (if to be installed) and the continuous emission monitor design detail to the CPM and the District at least 30 days prior to commencement of construction.

AQ-3 The project owner shall notify the District and the CEC of their intent to install oxidation catalyst, or provide manufacturer's guarantee that compliance with the VOC and CO emission concentration limits can be achieved by the dry low-NO_x combustors without oxidation catalyst at least 60 days prior to commencement of construction. [District Rule 2201]

<u>Verification:</u> The project owner shall provide a letter of intent to install a catalyst system or provide manufacturer's guarantee to meet the VOC and CO emission concentration limits stated in Condition **AQ-15** to the CPM and the District at least 60 days prior to commencement of construction.

AQ-4 Heat recovery steam generator (HRSG) design shall provide space for oxidation catalyst and additional selective catalytic reduction catalyst if required to meet CO, VOC, and NO_x emission limits. [District Rule 2201]

<u>Verification:</u> The project owner shall provide copies of the design drawings of the HRSG to the CPM and the District at least 30 days prior to commencement of construction.

AQ-5 Combustion turbine generator (CTG) and electric generator lube oil vents shall be equipped with mist eliminators. Visible emissions from lube oil vents shall not exceed 5% opacity, except for three minutes in any hour. [District Rule 2201]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-6 The CTG shall be equipped with continuously recording fuel gas flowmeter. [District Rule 2201]

<u>Verification:</u> The information above shall be included in the quarterly reports of Condition **AQ-31**.

AQ-7 CTG exhaust shall be equipped with continuously recording emissions monitor(s) dedicated to this unit for NO_x(before and after the SCR unit), CO, and O_2. Continuous emissions monitor(s) shall meet the requirements of 40 CFR part 60, Appendices B and F, and 40 CFR part 75, and shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEM(s) pass the relative accuracy requirement specified in condition **AQ-23**. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits in conditions **AQ-14, -15, -16**, and **-17**. [District Rule 2201]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-8 Exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods. [District Rule 1081]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-9 CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry standard cubic feet of natural gas. [District Rule 2201]

<u>Verification:</u> Please refer to Condition **AQ-30**.

AQ-10 Startup is defined as the period beginning with turbine initial firing until the unit meets the lbs/hr and ppmv emission limits in Condition **AQ-15**. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed one hour per occurrence. [District Rule 2201 and 4001]

<u>Verification:</u> Please refer to Condition **AQ-31**.

AQ-11 Ammonia shall be injected when the selective catalytic reduction system catalyst temperature exceeds 500 degrees F. The project owner shall monitor and record catalyst temperature at all times including periods of startup. [District Rule 2201]

Verification: The project owner shall record the SCR temperatures and the commencement of ammonia injection times in the daily logs required under Condition **AQ-31**.

AQ-12 The project owner shall monitor and record exhaust gas temperature at selective catalytic reduction system intake and oxidation catalyst (if installed) outlet. [District Rule 2201]

Verification: The project owner shall record the exhaust gas temperature at the SCR system intake and oxidation catalyst outlet in the daily logs required under Condition **AQ-31**.

AQ-13 Ammonia injection system shall be equipped with operational ammonia flowmeter and injection pressure indicator. [District Rule 2201]

Verification: The project owner shall record the flow of ammonia and the injection pressures in the daily logs required under Condition **AQ-31**.

AQ-14 During startup or shutdown of any combustion turbine generator(s), combined emissions from the two CTGs (S-3492-1 and '-2) shall not exceed the following: NO_x– 112.5 lbs and CO – 513.1 lbs in any one hour. [CEQA]

Verification: The project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-15 Emission rates from each gas turbine engine heat recovery steam generator exhaust except during startup and/or shutdown, shall not exceed the following:

PM10: 9.0 lbs/hr
SO_x(as SO_2): 3.5 lbs/hr
NO_x(as NO_2): 16.5 lbs/hr and 2.5 ppmvd @ 15% O_2 averaged over 1-hour
VOC: 2.8 lbs/hr and 1.2 ppmvd @ 15% O_2 averaged over 3-hours
CO: 24.1 lbs/hr and 6 ppmvd @ 15% O_2 averaged over 3-hours
Ammonia: 10 ppmvd @ 15% O_2 averaged over 24-hours
[District Rules 2201, 4001, and 4703]

Protocol: Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a 3-hour rolling average will commence on the hour. The 3-hour average will be compiled from the three most recent 1-hour periods. Each one-hour period in a 24-hour average for ammonia slip will commence on the hour. The 24-hour average will be calculated starting and ending at twelve-midnight. [District Rule 2201]

Verification: The project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-16 Emission rates from each CTG heat recovery steam generator exhaust, on days when a startup or shutdown occurs, shall not exceed the following:

PM10: 220.0 lbs/day
So_x(as SO_2): 83.7 lbs/day
NO_x(as NO_2): 421.5 lbs/day
VOC: 83.5 lbs/day
CO: 733.6 lbs/day
[District Rule 2201]

Protocol: Daily emissions will be compiled for a 24-hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: The project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-17 Annual emissions from the CTG calculated on a twelve consecutive month rolling basis shall not exceed the following: **(to be determined later)**

PM10: lbs/year
SO_x(as SO_2): lbs/year
NO_x(as NO_2): lbs/year
VOC: lbs/year
CO: lbs/year
[District Rule 2201]

Protocol: Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201]

Verification: The project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-18 Upon implementation of S-3492-1-0 and '2-0, emission offsets certificates shall be provided for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) in the following table atleast 30 days prior to the commencement of construction. **(to be determined later)**

	Quarter 1	Quarter 2	Quarter 3	Quarter 4
PM10				
SO_x(as SO_2)				
NO_x(as NO_2)				
VOC				

[District Rule 2201]

<u>Verification:</u> The project owner shall provide copies of all the necessary ERC certificates to the CPM no later than 30 days prior to the commencement of construction.

AQ-19 At least 30 days prior to commencement of construction, the project owner shall provide the District, with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into. [District Rule 2201]

<u>Verification:</u> The project owner shall provide copies of all the necessary ERC certificates to the CPM no later than 30 days prior to the commencement of construction.

AQ-20 Source testing to demonstrate compliance with the NOx, CO, and VOC short-term emission limits (lbs/hr and ppmv @ 15% O_2) shall be conducted within 60 days of initial operation of CTG and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rule 1081]

<u>Verification:</u> Please refer to the information requirements of Condition **AQ-25**.

AQ-21 Compliance with ammonia slip limit shall be demonstrated by using the following calculation procedure:

As = (((a-(b x c/1,000,000)) x 1,000,000 / b) x d)

Where:

As = Ammonia slip (ppmv @ 15% O_2)

a = ammonia injection rate (lbs/hr)/(17 lbs/lbs-mol)

b = dry exhaust gas flow rate (lbs/hr)/(29 lbs/lbs-mol)

c = change in measured NO_x concentration (ppmv @ 15% O_2) across catalyst, and

d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. [District Rule 4102]

<u>Verification:</u> The project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-22 Source testing to demonstrate compliance with PM10 short-term emission limit (lbs/hr) shall be conducted within 60 days of initial operation, again within 9 months of initial operation during the winter (December, January, or February), and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]

Verification: Please refer to the information requirements of Condition **AQ-25**.

AQ-23 Source testing of startup NOx, CO, VOC, and PM10 mass emission rates shall be conducted for one of the gas turbine engines (S-3492-1-0 or '-2-0) upon initial operation and at least once every seven years thereafter by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

Verification: Please refer to the information requirements of Condition **AQ-25**.

AQ-24 Compliance with natural gas sulfur content limit shall be demonstrated within 60 days of operation of each gas turbine engine and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]

Verification: Please refer to the information requirements of Condition **AQ-30**.

AQ-25 The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source tests required by conditions on this permit shall be submitted to the District within 60 days of testing. [District Rule 1081]

Verification: The project owner shall notify the CPM and the District 30 days prior to any compliance source test. The Project owner shall provide a source test plan to the CPM and District for the CPM and District approval 15 days prior to testing. The results and field data collected by the source tests shall be submitted to the CPM and the District within 60 days of testing.

AQ-26 The source test plans for the initial and seven-year source test shall include a method for measuring the CO/VOC surrogate relationship that will be used to demonstrate compliance with VOC lbs/hr, lbs/day, and lbs/twelve month rolling average emission limits. [District Rule 2201]

Verification: The Project owner shall provide a source test plan to the CPM and District for the CPM and District approval 15 days prior to testing.

AQ-27 The following test methods shall be used:

PM10:	EPA method 5 (front half and back half),
NO_x:	EPA method 7E or 20
CO:	EPA method 10 or 10B
O_2:	EPA method 3, 3A, or 20

VOC: EPA method 18 or 25
Ammonia: BAAQMD ST-1B
Fuel gas sulfur content: ASTM D3246.

EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]

Verification: As part of the test plan to be submitted under Condition **AQ-25**, the project owner shall identify the test methods to be used in the annual compliance source testing.

AQ-28 The project owner shall notify the District of a), the date of initiation of construction no later than 30 days after such date, b) the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and c), the date of actual startup within 15 days after such date. [District Rule 4001]

Verification: The project owner shall notify the CPM and the District of the date of initiation of construction no later than 30 days after such date. The project owner shall notify the CPM and the District of the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date.

AQ-29 The project owner shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmv @ 15% O_2), and hourly, daily, and annual records of NO_x and CO emissions. Compliance with the hourly, daily, and annual VOC emission limits shall be demonstrated by the CO CEM data and the CO/VOC relationship determined by annual CO and VOC source tests. [District Rule 2201]

Verification: The project owner shall provide records of the emissions as part of the quarterly reports of Condition **AQ-31**.

AQ-30 The project owner shall maintain records of SO_x lbs/hr, lbs/day, and lbs/twelve month rolling average emissions. SO_x emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201]

Verification: The project owner shall provide records of the information described above as part of the quarterly reports of Condition **AQ-31**.

AQ-31 The project owner shall maintain the following records for each CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 and 4703]

Verification: The project owner shall compile required data and copies of the daily logs and submit the information to the CPM in quarterly reports submitted no later than 60 days after the end of each calendar quarter.

AQ-32 The project owner shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 and 4703]

Verification: The project owner shall compile the required data in the formats discussed above and submit the results to the CPM as part of the quarterly reports of Condition **AQ-31**.

AQ-33 All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-34 Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

Verification: The project owner shall compile the required data in the formats discussed above and submit the results to the CPM as part of the quarterly reports of Condition **AQ-31**.

AQ-35 The project owner shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the Districts satisfaction that the longer reporting period was necessary. [District Rule 1100]

Verification: The project owner shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM as part of the quarterly reports of Condition **AQ-31**.

AQ-36 The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Verification: The project owner shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM as part of the quarterly reports of Condition **AQ-31.**

AQ-37 The project owner shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

Verification: The project owner shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM as part of the quarterly reports of Condition **AQ-31.**

AQ-38 Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

Verification: The project owner shall submit the continuous emission monitor audit results with the quarterly reports required of Condition **AQ-40**.

AQ-39 The project owner shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

Verification: The project owner shall submit the continuous emission monitor results with the quarterly reports of Condition **AQ-40**.

AQ-40 The project owners shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions; nature and cause of excess (averaging period used for data reporting shall correspond to the averaging period for each respective emission standard); corrective actions taken and preventive measures adopted; applicable time and date of each period during a CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Verification: The project owner shall compile the required data and submit the quarterly reports to the CPM and the APCO within 30 days of the end of the quarter.

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SJVUAPCD (San Joaquin Valley Air Pollution Control District) 1999g. Preliminary Determination of Compliance for the Sunrise Cogeneration and Power Project (98-AFC-4). Submitted to the California Energy Commission on November 19, 1999.

SJVUAPCD (San Joaquin Valley Air Pollution Control District) 1999h. Final Determination of Compliance and response to comments on the preliminary Determination of Compliance for the Sunrise Cogeneration and Power Project (98-AFC-4). Submitted to the California Energy Commission on November 19, 1999.

USEPA (United States Environmental Protection Agency/G. Robin) 1999b. Ambient Air Quality Impact Report (NSR 4-4-4, SJ 99-01). Submitted to the California Energy Commission on November 4, 1999.

APPENDIX A

CUMULATIVE AIR QUALITY IMPACT ANALYSIS

Technical Note
Cumulative Air Quality Impact Analysis

La Paloma Generating Station
Kern County, California

May 12, 1999

Prepared for:
Siting and Environment Division
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

1. INTRODUCTION

The objective of this modeling analysis is to quantify cumulative air quality impacts associated with the operation of La Paloma generating station with two other planned generating stations: Sunrise and Elk Hills. All three generating stations are to be located in Western Kern County, California.

In the present analysis, "cumulative" air quality impact means the sum total of air quality impacts from the three generating stations (GS) plus background concentration. The focus of this study is on the following pollutants:

- Carbon Monoxide (CO)
- Oxides of Nitrogen (NO_x)
- Sulfur Dioxide (SO_2)
- Fine Particulate (PM-10)
- Sulfate (SO_4)

2. CRITERIA FOR SIGNIFICANT IMPACT

In order for the cumulative impacts to be considered significant, two criteria would have to be met:

1. The maximum ground level concentration of any air pollutant emitted by the La Paloma GS would increase as a result of contribution from other existing or proposed sources. For the purposes of this analysis, there are no existing sources near the La Paloma GS and the only proposed emission sources are the Elk Hills and Sunrise generating stations.
2. Cumulative maximum ground level concentration would exceed California or Federal ambient air quality standards.

Cumulative air quality impact is considered insignificant unless both criteria are satisfied.

3. MODELING METHODOLOGY

The basic modeling methodology consisted of the following steps:

1. Run ISCST3 with emissions from La Paloma alone.
2. Re-run ISCST3 with emissions from all three plants. (La Paloma, Sunrise and Elk Hills).
3. If there is an increase in the ground level concentration (GLC) at the point of max as determined in Step 1, assess if the increased concentration is likely to violate applicable ambient air quality standard.

4. If there is no increase in max GLC at the point of max concentration, conclude that emissions from Sunrise and Elk Hills would not contribute to the max GLC associated with operation of La Paloma

3.1 SELECTION OF EMISSIONS/OPERATIONAL SCENARIO

Emissions from the three generating stations vary depending on ambient temperature and whether the plants are operating in 'normal' or 'startup' modes. For the purposes of this analysis it was assumed that La Paloma and Sunrise were operating normally at an ambient temperature of 65 F; it was assumed that Elk Hills was in a startup mode. These emissions scenarios were selected in consultation with CEC staff. A summary of emissions and other input data used in the modeling analysis are summarized below. The data were obtained from data files provided by the applicants.

Parameter	Units	La Paloma	Elk Hills	Sunrise
CO	lbs/hr	18.8	37.0	26.8
NO_x	lbs/hr	15.7	46.6	15.4
SO_2	lbs/hr	0.87	2.1	3.3
PM-10	lbs/hr	7.86	18.	18.
No. of Stacks		4	2	2
Stack Height	meters	30	36.6	30.5
Stack Diameter	meters	5.3	5.49	5.79
Exhaust Temp.	K	362	345.	368.
Exit Velocity	meters/ sec	18.5	12.5	13.0
Note: Emissions (lb/hr) are per stack.				

3.2 MODELING OF SO_X AND NO_X CONVERSION TO PARTICULATE MATTER

For NO_x emissions, the results of a recent modeling study by Desert Research Institute (DRI 1999) were used. This study concluded that approximately 33% of the NOx, emissions were converted to particulate matter. The time scale involved in this conversion is between 18 to 24 hours. Using these results, the maximum predicted ground level concentration was adjusted to allow for conversion form oxides of nitrogen (NO and NO_2) to nitrate. An estimate of particulate concentration due to secondary formation of nitrate would equal:

Max. Particulate concentration = Max. NO_2 Conc. x (100-66)/100

This approach yields only an order of magnitude estimate of nitrate concentration. A more refined approach that takes into account detailed atmospheric chemistry and the time variation of various chemical species affecting nitrate formation is beyond the scope of this evaluation.

For oxides of sulfur conversion to sulfate, it was assumed that emissions consisted entirely of SO_2 and that the conversion could be modeled as a first order chemical reaction. Under this assumption, one can model the SO_2 to sulfate conversion using a simple decay coefficient or a half-life for SO_2. The half-life of SO_2 varies between 1 to 4 days (Stern, et al, 1984). For the present analysis, a half-life of 8 hours was assumed. That is, 50% of the SO_2 is converted to sulfate in 8 hours. This half-life can be used in ISCST3 to account for the SO_2 to sulfate conversion.

3.3 Choice of Air Dispersion Model

EPA's ISCST3 air dispersion model was employed for this analysis. This model is recommended by the EPA's Guidelines of Air Quality Models for use in simple and complex terrain. Version 98356 was used to perform the model runs.

3.4 Choice of Meteorological Data

One year (1993) of hourly meteorological data were used to conduct the analysis. The surface data from McKittrick (Station 99991) were supplemented by upper air data from Bakersfield (99992). These data were taken from the input files provided by the applicant for the La Paloma project.

Since the focus of this study was on the cumulative air quality impacts associated with emissions from all three GS, the use of additional years of meteorological data would not change the results or conclusions reached in this study. In other words, the *relative contributions* of the Elk Hills and Sunrise GS emissions to the maximum GLC associated with the operation of La Paloma would remain the same.

3.5 Selection of Modeling Grid

A 2 kilometer grid (100 meter x 100 meter) was used to determine the location of GLC for each source. A second larger grid was used to enclose all three sources. This grid extended 20 km x 20km and was centered at the La Paloma GS. A rectangular coordinate system was used employing the UTM coordinate system.

RESULTS

The results of the analysis show that there would be minimal cumulative impact associated with operation of all three generating stations. For example, the maximum 1-hour NO_2 concentration due solely to emissions from La Paloma would not increase as a result of all three generating stations operating concurrently. For annual NO_2 concentration, there would be a minor increase. Specifically, the results were as follows:

Pollutant	Averaging Time	La Paloma GS	All 3 Stations
NO_2	1-hour	25.31	25.31
	Annual	0.300	0.343

PM-10	24-hour	1.10	1.12
	Annual	0.150	0.172
SO_2	24-hour	0.123	0.124
	Annual	0.0167	0.0202
CO	1-hour	30.45	30.46
	8-hour	7.72	7.72

Overall, the analysis showed that inclusion of emissions from the proposed Sunrise and Elk Hills generating stations leads to a new point of maximum ground level concentration. This shown in the attached contour plots of concentration for emissions from (a) La Paloma; (2) La Paloma, Elk Hills and Sunrise, and (3) Elk Hills and Sunrise. A comparison of Figures 1 and 2 (1-hour NO_2, La Paloma and All 3 Stations), shows negligible contribution in the vicinity of La Paloma from the other two plants.

Figure 2 shows that a new point of maximum concentration near Elk Hills and Sunrise generating stations. This is due entirely from emissions from these two plants as can be confirmed in Figure 3 (Sunrise and Elk Hills). The same pattern was identified for annual NO_2 concentrations as shown in Figures 4-6.

Particulate impacts associated with the conversion of NO_2/NO to nitrate are estimated to be 1 ug/cubic meter. This is based on 33% conversion of the maximum 24-hour averaged NO_2 concentration associated with operation of La Paloma GS. The latter range between 0 to 0.3 ug/cu/meter on a 24 hour basis. The impact of secondary nitrate formation on the PM-10 concentration is not considered significant.

It was noted in Section 3.2 that the time scale for the conversion of NO_2/NO to nitrate is between 18 to 24 hours. This means that areas that are located 175 to 200 miles to the southeast would be impacted with higher nitrate particulate. This would transport the plume out of Kern County to adjacent counties located to the East or Southeast. This estimate is based on the fact that on an annual basis, the predominant winds in Kern County are from the NE with an average annual speed of 8.9 mph (Ref: California Surface Wind Climatology, CARB, June 1984).

Use of the ISCST3 model with a half-life of 8 hours indicates that the maximum 24-hour ground level concentration of SO_2 would decrease from 2.5 ug/cu meter to 2.4 ug/cu meter. This means that about 4% of the SO_2 (0.1 ug/cu meter) would be converted to sulfate. Since the state standard for sulfate is 25 ug/cu meter, the secondary formation of sulfate is not considered significant.

As with NO_2/NO conversion to nitrate, the SO_2 to sulfate conversion takes place over a period of 1-4 days. On this time-scale the emissions would be transported several hundred miles to the East or Southeast. Therefore the highest concentration of sulfate would not occur near the power plants but several hundred miles to the East or Southeast. For example, in 2 days the plume would travel approximately 400 miles from the source. This would transport the sulfate (and nitrate particulates) out of Kern County and possibly, out of state.

APPENDIX B

EVALUATION OF POTENTIAL EMISSION IMPACTS DUE TO TRANSMISSION CONSTRAINTS

By Mark Hesters

INTRODUCTION

The purpose of this study is the analysis of the potential environmental (air quality) effects in northern California[2] created by the operation of new generation in Kern county, south of Path 15[3]. The Transmission Agency of Northern California (TANC) requested this study as part of the Sunrise Cogeneration and Power Project's (Sunrise) certification process at the California Energy Commission. This study will analyze the ways in which new power plants operating south of Path 15, by increasing Path 15 congestion, could change electric power production and as a consequence, create environmental effects in Northern California.

BACKGROUND:

There is the potential for significant power plant development in Kern county, south of Path 15. So far three companies have applied to the Commission for certification of plants in Kern County and staff expects one more to apply in December 1999. If all four of these power plants are constructed, their operation will increase the flow of electricity on the transmission lines leaving the Midway substation near Buttonwillow in Kern County.

TANC has intervened in the Sunrise certification process at the California Energy Commission with two concerns. First, TANC is concerned that operation of new plants in Kern County will limit their members' access to transmission capacity on Path 15, thus limiting their access to power from Southern California[4] and the Southwest[5]. Second, TANC contends that limiting its members' access to power from Southern California and the Southwest, could adversely impact air quality in Northern California.

TANC members have rights to 300 MW of transfer capability between the Midway substation and the California-Oregon Transmission Project (COTP) which terminates at the Tesla substation. The critical limiting transmission lines between the Midway and COTP are Path 15. Staff understands that these firm rights could be temporarily taken away when Path 15 is congested. When this occurs, TANC members could have less access to power south of Path 15[6]. If TANC members are not able to get power from south of Path 15, they would purchase or generate energy north of Path 15. The source of energy north of Path 15 may have environmental impacts similar to or different from the source of energy that TANC members would have otherwise utilized south of Path 15.

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2 For the purpose of this report, Northern California will refer to electric loads and resources north of Path 15.

3 Path 15 the set of lines that limit the import of power into Northern California from Southern California and hence the Southwestern United States. The full description of Path 15 from the Western Systems Coordinating Council's (WSCC) Path Rating Catalog is contained in attachment 2.

4 Southern California refers to electric generators and loads electrically south of Path 15.

5 The Southwest includes Nevada, Arizona, Utah, Colorado and New Mexico.

6 It is important to note that any plant operating south of Path 15, not just the Sunrise project, could cause congestion on the Path and reduce TANC members' ability to import power.

Because purchasing or generating power North of Path 15 could change the operation of existing power plants in Northern California, the environmental impacts that would arise from this shift would likely be those that are related to plant operation. Variations in plant operation would primarily affect air emissions, although cooling water and materials used to control plant air emissions could be affected as well. Changes in plant operations could negatively affect air quality in three ways: first, by increasing the quantity of power generated in northern California; second, by increasing the generation from plants that emit air pollutants at higher rates than those that would generate south of Path 15; and third, by increasing generation from plants in regions with more severe air quality problems. This analysis does not evaluate the potentially beneficial effects that would be created by reducing generation south of Path 15.

ANALYSIS

This analysis will first look at how congestion on Path 15 would affect the quantity of energy generated in Northern California. Then, the potential for Path 15 congestion to shift generation from plants that emit fewer amounts of air pollutants to plants that emit more pollutants will be analyzed along with the potential for the location of generation to shift. Increased Path 15 congestion could also have positive environmental effects in northern California by reducing generation northern California, and shifting generation to plants that emit pollutants at a lower rate or are located in less critical areas.

Utilities serve electric loads in Northern California by producing power locally, importing power from the Pacific Northwest[7], and importing power from Southern California and the Southwest. Thus, for the same level of demand, an increase in power supplied by one of the three sources will require an equivalet decrease in the power supplied by the other two sources combined. Path 15 limits the quantity of power that can be imported into Northern California from Southern California and the Southwest.

Because congestion on Path 15 does not affect the demand for electricity in Northern California then a fixed quantity of electricity must come to Northern California from a combination of the three sources. Table 1 describes a very simplified electric system representing Northern California as 20,000 megawatts (MW) of load being supplied by three regional electricity sources. Attachment 1 contains a bubble diagram of this system. It is a simplified system because Northern California is made up of many utilities including PG&E and TANC members, and each of the three regional electricity sources in Table 1 consist of many power plants. However, this is an accurate, if generalized, description of the way loads are served in Northern California.

Table 1 contains three “resource scenarios”, Cases 1, 2, and 3, each requiring 20,000 MW of generation to serve 20,000 MW of load. The quantity of power

[7] The Pacific Northwest includes Oregon, Washington, Idaho, Montana, Wyoming, British Columbia and Alberta.

needed in Northern California does not significantly change with the source of the power[8]. In each scenario 20,000 MW of Northern California load is served in total by power generated in Northern California, power imported from the Northwest and power imported from the south over Path 15. For the purpose of this example, Northern California cannot import more than 3,300 MW over Path 15[9]. Thus, Path 15 is congested when 3,300 MW are imported into Northern California from regions south of Path 15.

Case 1: the Sunrise power plant is not operating, TANC members are not using their 300 MW of Path 15 capacity and Path 15 is not congested. Table 1 shows that 13,000 MW of generation in Northern California, 4,000 MW of imports from the Northwest[10] and 3,000 MW of imports over Path 15 supply the 20,000 MW of Northern California load.

Case 2: The Sunrise project is operating and Path 15 is congested. The Sunrise plant generates 300 MW and Path 15 is congested with a total of 3,300 MW flowing over the lines. Table 1 shows that the additional 300 MW from Sunrise displaces 300 MW of local generation in Northern California[11]. Thus, 12,700 MW of generation in Northern California, 4,000 MW of imports from the Northwest and 3,300 MW of imports from south of Path 15 serve the 20,000 MW Northern California load.

Case 3: The Sunrise project is not operating and Path 15 is congested by TANC members using their 300 MW of Path 15 import capacity. Table 1 shows that 12,700 MW generation in Northern California, 4,000 MW of imports from the Northwest and 3,300 MW imports from south of Path 15 serve the 20,000 MW Northern California load.

[8] Changing the power sources could slightly increase (or decrease) line losses and result in the need for more (or less) electric power.

[9] The actual south to north limit for Path 1 varies between 3,300 MW and 3,900 MW.

[10] For all three cases Northwest imports are fixed at 4,000 MW. The WSCC 1999 path Rating Catalog sets the limit for the primary path limiting these imports, the California-Oregon Intertie, at 4,800 MW; however this rating has varied.

[11] The total power provided to Northern California must total 20,000 MW. If 300 MW more come over Path 15 then generation in Northern California and imports from the Northwest must generate a total of 300 MW less.

Table 1
Northern California Electricity Supplies
For the Three Cases
(MegaWatts)

	Case 1	**Case 2**	**Case 3**
Northern California Load	20,000	20,000	20,000
Generation in Northern California	13,000	12,700	12,700
Imports over Path 15	3,000	3,300	3,300
Northwest Imports	4,000	4,000	4,000
Total Power Supplied to Northern California	**20,000**	**20,000**	**20,000**
Case 1: Path 15 is not congested. Case 2: Path 15 is congested with power generated by Sunrise. Case 3: Path 15 is congested with imported power purchased by TANC.			

The three cases show that any increase in imports into Northern California over Path 15 should not cause generation in Northern California to increase. Instead, any increase in imports over Path 15 will be accompanied by a similar reduction in power generated in Northern California or power imported from the Northwest. Power coming into Northern California over Path 15 as TANC imports has the same impact as Sunrise imports, although, the operation of power plants in Northern California could be affected.

The operation of new power plants south of Path 15 doesn't increase the amount of energy generated in northern California, it changes whose load is served by power imported over Path 15. PG&E and TANC member customers' electricity demands comprise over ninety-five percent of the northern California load. The operation of new plants south of Path 15 would require TANC members to serve more of their loads with power north of Path 15. If new plants are not operating south of Path 15 then plants operating north of Path 15 would serve more of PG&E's customers' loads. The operation of plants north of Path 15 would change only if TANC members would get their power from different northern California sources than PG&E.

Both PG&E and TANC members have access to the same sources of northern California power, although the cost of that power may vary. PG&E serves it's customers with electric power in northern California from a variety of sources including nuclear, wind, geothermal, hydroelectric, solar, biomass and natural gas plants. After 2002 most of these plants will provide electricity to PG&E customers through the California Power Exchange[12]. TANC members have their own power supplies which include most of the same types of resources as PG&E accesses, plus they have the option to negotiate contracts with plants that would otherwise serve PG&E customers through the Power Exchange. TANC members can access the same northern California resources as PG&E although, the costs may be different because TANC members would have to pay for the cost of delivering the power from the generator to the load. Assuming both PG&E and TANC members try to minimize the cost of serving their electric loads, the supplier would be the same unless TANC members were unable to deliver the power to their load.

Any power source that could supply a PG&E load should be able to supply a TANC member load. TANC members have access to the PG&E transmission system and are able to contract for power from any provider. This makes any generation resource available to serve PG&E load available to serve TANC load. However, there may be instances where local transmission constraints prevent a TANC member from access to a specific energy provider. However, this is not likely and becomes less likely as new plants are constructed and operated in northern California. TANC members that have access to power generated south of Path 15 must be able to transmit that power from the terminus of Path 15 to their load. Many existing and proposed power plants would send power to TANC members over the same lines that would have been used to transmit south of the Path 15 imports. Thus, differences in PG&E and TANC members access to generators should not change the operation of plants north of Path 15 when new plants operate south of Path 15.

CONCLUSION

New electric power plant development in Kern County and other areas south of Path 15 should have at most, minor environmental impacts in Northern California and may have commensurate benefits in Southern California that are specifically examined in this analysis. Power plant development south of Path 15 may increases congestion on Path 15 but will not increase the quantity of power generated in Northern California. In fact, new generation south of Path 15 could reduce the quantity of power generated in Northern California. Thus, new power plants south of Path 15 will not adversely affect the air quality and the environment in Northern California by increasing electricity production in Northern California.

Increases in Path 15 congestion caused by new power plants south of Path 15 could change the way plants in Northern California operate. This may have an adverse affect on Northern California air quality. However, as was explained in the above analysis, the operation of plants in Northern California will change only when the power purchasing decisions of PG&E are different than those of TANC members. The differences in these decisions and their effect on air quality in Northern California should not be significant.

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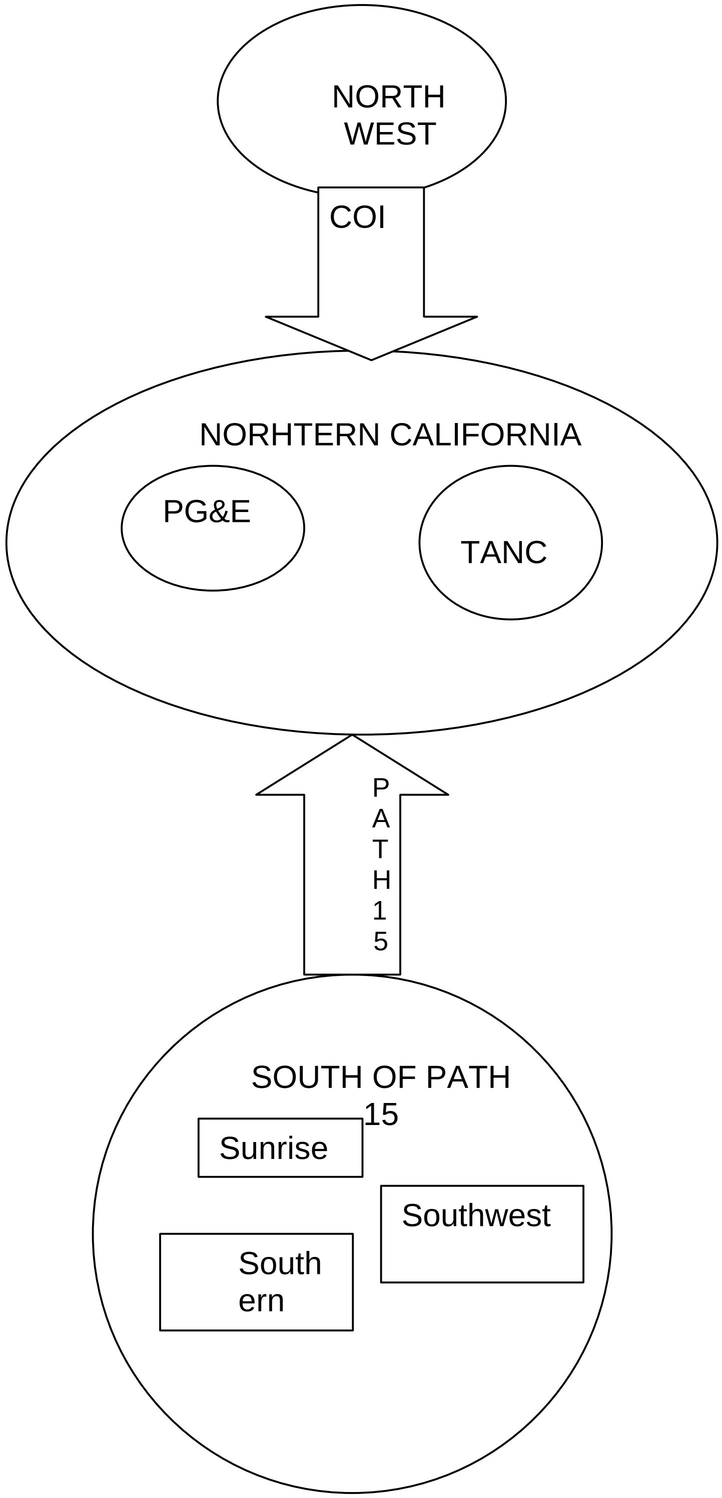
[12] The California Power Exchange is an electricity market, which tries to minimize the cost of serving loads based on bids it receives from power providers.

ATTACHMENT 1



15. Midway - Los Banos

PART VI

Item 1-37

Revised February 1999

15. Midway - Los Banos

Accepted Rating ☐
Existing Rating ☒
Other ☐

Location:	Between central and southern California within the PG&E system and south of Los Banos substation (PG&E internal Path 15).
Definition:	Midway-Los Banos #1 and #2 500 kV lines Gates-Panoche #1 & #2 230 kV lines Gates-Gregg 230 kV line Gates-McCall 230 kV line
Transfer Limit:	3300-3900 MW south to north. Transfer limits are affected primarily by (1) the status of the series capacitors at Los Banos, (2) the Helms pumping levels, (3) generation and load levels in the Fresno area, and (4) the level of available remedial actions in the PG&E service area for a double line outage south of Los Banos (generation dropping south of Path 15 and load dropping north of Path 15).
Critical Disturbance that limits the transfer capability:	A double line 500 kV outage between Los Banos and Midway substations. This will result in rated flow in the Gates-Panoche 230 kV lines. It may also result in minimum reactive margins at buses in the vicinity of Gates and Panoche as well as at buses in southern Idaho under some conditions.
When:	The path limit was established on February 1, 1993.
System Conditions:	The path limit is based on south to north transfers under light winter operating conditions.
Study Criteria:	The path limit was established fully meeting the WSCC Reliability Criteria for double line outages. All facilities were loaded within normal ratings under normal system conditions. All facilities were loaded within emergency ratings under outage conditions. Post-transient voltage criteria was met.
Remedial Actions Required:	CDWR and PG&E pump load dropping north of Path 15. PG&E service area load dropping north of Path 15. PG&E service area generation dropping south of Path 15.
Formal Operating Procedure:	California ISO T-120 (Adverse Operating Conditions). California ISO T-122 (West of Borah versus Path 15 Nomogram).
Allocation:	PG&E, SCE, SDG&E, CDWR
Interaction w/Other Transfer Paths:	It may be necessary to reduce the south-to-north transfers to accommodate Borah West transfers in excess of 1850 MW.
Contact Person:	Ben Morris Pacific Gas & Electric 77 Beale St. N3B San Francisco, CA 94106 (415) 973-7687 (415) 973-3479 - fax bem8@pge.com

PART VI Item 1-38

PUBLIC HEALTH

Testimony of Obed Odoemelam and Rick Tyler

INTRODUCTION

Operating the proposed Sunrise Cogeneration and Power Project (SCPP or the Sunrise project) would create combustion products and possibly expose workers and the general public to these pollutants as well as the toxic chemicals associated with other aspects of facility operations. The issue of possible worker exposure is addressed in the Worker Safety and Fire Protection section of this Final Staff Assessment (FSA) with the exception noted below. Exposure to electric and magnetic fields (EMF) is addressed in the Transmission Line Safety and Nuisance section. The purpose of this public health analysis is to determine whether a significant health risk would result from human exposure to (a) the operations-related chemicals, (b) combustion by-products emitted during routine operations, and (c) toxic pollutants encountered as soil contaminants at the project site.

The exposure evaluated in this analysis is to pollutants for which no air quality standards have been established. These are known as the noncriteria pollutants, or toxic air pollutants. Those for which ambient air quality standards have been established are known as criteria pollutants. These criteria pollutants are identified in this section (along with regulations for their control) because of their contribution to the total pollutant exposure in any given area. Furthermore, the same control technologies may be effective in controlling both types of pollutants when emitted from the same source. Compliance with the required control technologies is discussed in the Air Quality section.

LAWS ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

The Clean Air Act of 1970 (42 U.S.C., section 7401 et seq.) required establishment of ambient air quality standards to protect the public from the effects of air pollutants. These standards have been established by the United States Environmental Protection Agency (EPA) for the major air pollutants, nitrogen dioxide, ozone, sulfur dioxide, carbon monoxide, sulfates, particulate matter with a diameter of 10 micron or less (PM10) and lead. The Act required states to adopt plans to ensure compliance by 1982.

STATE

California Health and Safety Code section 39606 requires the California Air Resources Board (CARB) to establish California’s ambient air quality standards to reflect the California-specific conditions that influence its air quality. Such standards have been established by the CARB for ozone, carbon monoxide, and sulfur dioxide, PM10, lead, hydrogen sulfide, vinyl chloride and nitrogen dioxide. The same biological mechanisms underlie some of the health effects of most of these and the noncriteria pollutants. The California standards are listed together with the corresponding federal standards in the **Air Quality** section.

California Health and Safety Code section 41700 states that “No person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause or have a natural tendency to cause injury or damage business or property.”

The California Health and Safety Code section 39650 et seq.mandates the California Environmental Protection Agency (Cal-EPA) to establish safe exposure limits for toxic, noncriteria air pollutants and identify the best available methods for their control. These laws also require that the new source review rules for each air district include regulations establishing procedures to control the emission of these pollutants. The toxic emissions from natural gas combustion are listed in CARB’s April 11, 1996 California Toxic Emissions Factors (CATEF) database for natural gas-fired combustion turbines. Cal-EPA has developed specific cancer potency estimates for assessing their related cancer risks at specific exposure levels. For noncancer-causing toxic air pollutants, Cal-EPA established specific no-effects levels (known as reference exposure levels) for assessing the likelihood of producing health effects at specific exposure levels. Such health effects would be considered likely only when exposure exceeds these reference levels. Staff uses these Cal-EPA potency estimates and reference exposure values in its health risk assessments.

California Health and Safety Code section 44300 et seq. requires facilities, which emit large quantities of criteria pollutants and any amount of noncriteria pollutants to provide the local air district an inventory of toxic emissions. Such facilities may also be required to prepare a quantitative health risk assessment to address the potential health risks involved. The CARB and the air quality management districts (Air Districts) are responsible for implementing these requirements for new emission sources.

LOCAL

The San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) has no specific rules implementing Health and Safety Code section 44300. It does, however, require the results of a health risk assessment as part of the application for the Authority to Construct (ATC). SCPP has complied with this requirement.

SETTING

According to information from the applicant, the Sunrise Cogeneration and Power Company, the Sunrise project will be located on a 16-acre site within the Midway-Sunset oil fields. The toxic pollutants from the project will be emitted into a sparsely populated, mostly agricultural area with oil and gas production fields (SCPP 1998a pages 1-1, 1-4, and 8.6-1 through 8.6-3) with specific locations of soil contamination from past production activities (SCPP 1998a pages 8.13-1 and 8.13-2). The nearest residence to the site is approximately 1.3 miles to the east. The nearest communities of any significant size are Fellows, approximately 3 miles to the South and Derby Acres about 3 miles to the north. The population density of the area according to the 1990 U.S census figures is 19 persons per square mile.

The only facility with sensitive receptors within a 6-mile radius is the Midway school, six miles to the south. Another school, the McKittrick School, is approximately 6.5 miles to the north. Such sensitive receptors (which are children in this case) are usually more susceptible than the general population to the effects of environmental pollutants. Extra consideration is given to possible effects in such individuals in establishing exposure limits for environmental pollutants. The individuals potentially exposed around the project site include residents in two houses less than a mile away (along Highway 33), and workers around the site (SCPPa page 8.6-3). Potential worker exposure is assessed using established work place exposure standards.

METHOD OF ANALYSIS

Any impacts from sources such as the proposed Sunrise project would be associated with soil contaminants at the project site, the toxic pollutants originating from the combustion turbines, ammonia from the selective catalytic reduction (SCR) system, and toxic chemicals from the cooling towers. For all such sources, potential public or worker exposure is estimated through air dispersion modeling. The modeling approach employed by staff for this and similar projects is more fully discussed in the **Air Quality** section. Using the modeled exposure estimates, staff determines whether each pollutant of concern would pose a significant health risk to workers or the general public located away from the site. For noncarcinogenic pollutants, staff compares potential significance of effects by comparing exposure estimates with the applicable public reference levels, or worker exposure standards For carcinogenic pollutants, comparing the estimated cancer risk with the established level of regulatory significance makes such determination. When exposures fall below either reference levels or levels of cancer-specific significance, staff regards the source as unlikely to contribute significantly to pollution levels in the area. When such potential exposures are above their levels or health significance, staff may recommend mitigation. The procedure for evaluating the potential for health significance is known as a health risk assessment process, which consists of the following steps:

4. A hazard identification step in which each pollutant of concern is identified along with its possible health effects.
5. A dose-response assessment step in which the relationship between exposure and the probability of effects is established.
6. An exposure assessment step in which the possible extent of exposure is established by dispersion modeling for all possible pathways.
7. A risk characterization step in which the nature and magnitude of the possible health risk is assessed.

HEALTH EFFECTS ASSESSED

Pollution-related symptoms from sources like the Sunrise project are evaluated separately for acute effects and chronic effects. Acute effects are those that result shortly after exposure while chronic effects are those that result from long-term exposure. The acute effects usually result from high-level exposures, which normally occur during accidental releases, not routine operations when emissions are much lower. Chronic effects usually occur at low levels of exposure and produce effects, which may manifest as cancer or other effects long after the beginning of exposure. Since acute effects are not usually expected from routine operation of sources like the Sunrise project, the potential for chronic effects has become more important than that for acute effects in assessing emission impacts.

METHOD FOR DETERMINING THE LIKELIHOOD OF NONCANCER EFFECTS

The method used by regulatory agencies to numerically establish the likelihood of significant noncancer impacts is known as the hazard index method; it is used to evaluate both acute and chronic effects. In this method, a hazard index is calculated for the individual pollutants by dividing estimated exposure levels by their established reference levels. A hazard index of less than 1.0 suggests that acute or chronic effects that pollutant would be unlikely. A value of 1.0 or more would suggest a likelihood of effects but does not demonstrate that such effects will occur. The indices for all pollutants are then added together to obtain a total hazard index value for the source in question. A total index of less than 1.0 would suggest a potential lack of effects from the interaction of all the pollutants considered. A value of more than 1.0 would suggest a potential for significant interactive effects, but is not regarded as proof that such effects will occur. In such a case, staff does not recommended specific regulatory action without completing a more refined analysis. The potential for a significant cancer risk is assessed using a different approach.

METHODS FOR ASSESSING THE POTENTIAL FOR A SIGNIFICANT CANCER RISK

Cancer from exposure to carcinogenic exposure usually results from biological effects at the molecular level. Since such effects are currently assumed possible from every exposure to a carcinogen, the risk of cancer is generally considered by staff and other regulatory agencies as more sensitive than the risk of noncancer effects in assessing the potential for a significant health hazard. Such sensitivity accounts for the high level of significance currently accorded the numerical estimates of cancer risks in the environmental risk assessment process. For any source of concern, the potential cancer risk is obtained by multiplying the exposure estimate by the potency values for the individual carcinogens emitted. The potency value is established from animal or human data to reflect the cancer-causing efficiency of each carcinogen as compared to the others. The total cancer risk is obtained for the project by adding together the risk values obtained for each of the individual carcinogens. In this assessment process, the exposure that produces the cancer is conservatively assumed to occur at the same level for a 70-year lifetime to minimize the possibility of underestimating the actual cancer risk. In practice, however, only the highest possible risk is obtained with this method. The actual risk would likely be lower and could indeed be zero. It is, therefore, important to interpret the results of such assessments with caution.

STAFF'S SIGNIFICANCE CRITERIA

Staff considers a potential cancer risk of one in a million as the threshold of significance for sources of environmental carcinogens. Above this threshold, further mitigation could be recommended after proper consideration of issues related to the conservatism of the assessment process. For noncarcinogenic pollutants, staff will consider significant health impacts unlikely when the hazard index estimate is less than 1.0. If 1.0 or more, staff would regard the related emissions as potentially significant and may recommend mitigation after a more refined analysis.

PROJECT SPECIFIC IMPACTS

IMPACTS RELATED TO THE PRESENCE OF SOIL CONTAMINANTS

CURE has raised a concern about the potential for health impacts from the handling and disposal of contaminated soil during the construction phase. The applicant has identified several locations of oil contamination (SCPP 1999s). A list of contaminants was provided by the applicant along with the levels measured (in the parts per million range) during the Phase II site assessment. In their soil-bound form, workers could be exposed to these pollutants by inhalation as the disturbed, contaminated soil is released into the air. They could also be exposed when the soil is ingested directly or through soil contaminated food. Since no food is produced in the area and adult workers are unlikely to ingest the soil in significant amounts, staff considers inhalation as the only route of significance with respect to potential on-site exposure. We therefore, do not agree with (CURE 999j, page 18) that other exposure pathways would be significant during site grading or other construction activities. The two contaminants of most concern to CURE are the carcinogenic arsenic and chromium, which were measured at the parts per million levels. Given the magnitude of the cancer risks possible at such concentrations, staff does not consider these contaminants as posing a significant health to humans when the soil is handled as recommended in the **Waste Management** section. CURE disagrees with staff. They contend instead that these soil contaminants would pose a significant worker health risk in this construction phase and characterized staff's mitigation as inadequate as proposed in the **Waste Management** section (CURE 1999j, pages 17 through 20). Staff disagrees, and considers CURE's conclusions flawed. These flaws are addressed more fully below.

FLAWS IN CURE'S CONCLUSIONS ABOUT THE POTENTIAL HEALTH RISKS ASSOCIATED WITH SOIL CONTAMINATION AT THE PROJECT SITE.

In asking that the project site be remediated before Commission certification, CURE (1999j , page 19) assumed that workers and the general public would be exposed at levels capable of significant health impacts. They did not make any actual measurements (CURE 1999j pages 13 through 17). CURE based this assumption on the history of oil production activities at the site. Staff regards this approach to hazard characterization as significantly flawed, especially when relied upon for demands for pre-construction remediation. CURE (1999j, page 15) lists a number of oil production-related carcinogens and neurotoxins, which they argue may be present at potentially toxic levels. They identified carcinogenic arsenic and chromium as the two substances of most concern to them. As CURE must know, however, the mere presence of a toxicant at a site does not necessarily constitute a risk to human health. Only the actual dose to humans will be exposed can be used to determine the possibility of significant effects. Any such dose can only be estimated from actual measurements. Failure to obtain such measurements renders the estimates of their potential health risks possible unreliable.

In its analysis, the applicant first established the concentration of the contaminants at issue, then assessed their potential effects at the locations of interest. These concentrations were derived from Phase II Site Assessment surveys conducted by the applicant (SCPP 1999s). Given (a) the nature of the contaminants present and (b) their concentrations as established from actual measurements, only chronic health effects are considered possible by staff from construction activities. As noted in the appendix to this report, staff's calculations have shown that these contaminants would be unlikely to pose a significant health to either the public, or workers engaged in construction activities. The measures specified as conditions for certification in the **Waste Management** section are intended to ensure (a) the prompt detection and removal of any contaminated soil, (b) appropriate handling and disposal of such soil, and (c) reduction of human exposure to the extent feasible.

To strengthen their argument for pre-certification remediation, CURE provided an EPA document (EPA 1999a) prepared as an update to the EPA Region 9 PRG (Preliminary Remediation Goals). Staff has reviewed this document and found it to be appropriate only for assessing the adequacy of specific soil clean-ups, and not for determining the need for initiating such clean-ups. It also is not intended for assessing the possible health risk from a contaminated site as CURE contended at the hearings. CURE is, therefore, wrong in claiming that this document supports their call for a pre-certification clean up of the project site.

IMPACTS RELATED TO EMISSIONS FROM CONSTRUCTION EQUIPMENT AND VEHICLES

Another construction-related impact of the proposed Sunrise project is caused by worker or public exposure to emissions from the earth-moving equipment and vehicles to be used for site grading and other aspects of facility construction. Both criteria and noncriteria pollutants could have significant effects in this regard. The potential impacts of the criteria pollutants are addressed in the Air Quality section along with mitigation measures for those to be emitted at potentially significant levels. The noncriteria pollutants from such sources are emitted, and generally considered together by staff as volatile organic compounds (VOCs). Their emission rates relative to the Sunrise project are specified in the Air Quality section. Our Air Quality staff does not conclude that these pollutants can cause a significant adverse effect. Given (a) the relatively low levels of emission and, (b) the types of health impacts that could result from exposure to these pollutants, staff concludes exposure would not cause insignificant acute and chronic health impacts.

While CURE agrees with staff that construction-related exposures would occur within a period too short to lead to chronic effects (CURE 1999g, page 15), they disagree with staff's findings of insignificant acute effects among on-site workers or the nearest residents. According to CURE, staff's finding of insignificant impacts is flawed for three reasons: (1) staff's use of CARB-established acrolein emission factor in modeling potential impacts, (2) staff's use of inappropriate meteorological data in modeling exposure levels for both acrolein and the other pollutants of interest and, (3) staff's failure to include background levels in assessing the potential for impacts. Staff disagrees, and considers its analysis as appropriate. We will separately refute the accuracy of CURE's characterization of staff's assessment approach.

FLAWS IN CURE'S CONCLUSIONS ON STAFF'S USE IF AVAILABLE METEOROLOGICAL DATA

CURE contends that staff's should have calculated exposures the meteorological data for Mckittrick instead of that for Fellows. As noted by CURE, (1999g, page 3) the McKittrick data was recorded over a three-year period, and includes many more modeling parameters than the Fellows data. Because both Fellows and McKittrick are within 7 miles of the project site, CURE concludes that the use of data that was recorded at either location would be adequate to yield reliable exposure estimates for emissions from the Sunrise project. However, since the McKittrick data was recorded over a longer time period, and is more complete, CURE considers it more appropriate for the Sunrise project than the Fellows data. In reaching this conclusion, CURE failed to consider that Fellows is much closer to the project site than McKittrick, making it more appropriate to use its meteorological data to model for the Sunrise project. As a result, staff believes that the Fellows data is more appropriate for modeling. The Air District (SJVUAPCD 1999h) which assessed both data sets according to specified EPA criteria reached the same conclusion. The Air District later demonstrated the validity of this conclusion through modeling conducted using each data set. Since the Fellows data has been demonstrated as appropriate for modeling the impacts of the Sunrise project, staff (a) does not consider CURE's criticisms as necessary and (b) does not consider it necessary to remodel the project's impacts using McKittrick data as called for by CURE.

FLAWS IN CURE'S ARGUMENT AGAINST STAFF'S CHOICE OF ACROLEIN EMISSION FACTORS IN MODELING IMPACTS

As will be noted for the other types of exposure, the difference between CURE's and staff's conclusions about the potential impacts of project-related emissions is driven almost completely by the differences in the acrolein-specific emission factors used by CURE and staff. Acrolein is an important combustion product because of its toxicity at relatively low levels. It is found in tobacco smoke, vehicular emissions, and emissions from coal- or oil-fired power plants. In several large cities, background levels have been measured at 9 parts per billion (9ppb). Occupational exposures occur in industries that use acrolein to produce other chemicals (Agency for Toxic Compounds and Disease Registry 1989). Acrolein has not been established as a human carcinogen, and therefore, the hazard is assessed in terms of noncancer effects. As noted by CURE (1999g, page 50) the reference exposure level for acute effects within the general public (as distinguished from workers) has been reduced by Cal/EPA to better protect against such effects. The new reference level of 0.19 ug/m3 was published in 1999 after the AFC for the Sunrise project was filed. The health end point considered in setting this new exposure limit is mild eye irritation, which is not as severe as those considered in setting the limits for several other pollutants. Since there presently is no generally accepted method for factoring the severity of effects in calculating numeric exposure limits for environmental pollutants, the regulatory significance of such exposure limits should be assessed with caution

Staff notes that neither the reference level for long-term public exposures, nor the short-term exposure standards for acute worker effects was changed by Cal/EPA. Both staff and the applicant used these unchanged reference levels and exposure standards in their analyses that found that significant acute impacts would be unlikely within exposed workers or the general public. CURE analyzed the project's potential impacts using this new reference value and claimed that staff should do the same. However, CURE's analysis used the new reference limit for assessing the potential for acute impacts for both the general public and the potentially exposed workers while it should have been used only with places of human habitation.

In establishing an emission factor for acrolein assessment, CURE multiplied all concentrations of acrolein by ten to correct for the flaws CURE identified in the test method used by CARB for acrolein measurements (CURE 1999g, page 50). While there is some merit to CURE's concern about this test method, staff considers this 10-fold adjustment as arbitrary and likely to lead to an overestimation of both acrolein emissions and the potential impacts of such emissions. This staff supposition is borne out by data in both the document (Shauer et al 1999) that CURE relied upon, and the CARB (1991) document specifying the composition of organic pollutants from combustion of common fuels. As staff established from these and other sources, acrolein emissions from diesel or gasoline engines should range between 10% and 15% of that for formaldehyde. The use of CURE's emission derivation approach would increase this percentage to about 74%. This overestimation is the main reason for CURE's findings of potentially significant acute acrolein effects with respect to both construction-related and turbine emission. (CURE 1999g, pages 55 and 60). We specifically note in this regard, that CURE's acute hazard index value for the six pollutants (acrolein, benzene, formaldehyde, styrene, toluene and xylene) they considered for evaluating construction impacts is 302.8. The value for acrolein alone is 302. Without this acrolein number, the value for the other five would be 0.82, showing that these five pollutants would not pose a health hazard as staff expects for the types of construction activities involved.

Even if staff were to accept the a ten-fold increase in the emission factor as appropriate for acrolein, we would still find that their finding of significant acute worker impacts is incorrect using the more appropriate worker exposure standard of 750 ug/m3 (National Institute for Safety and Health, NIOSH, 1994) instead of the non-worker exposure reference level of 0.19 ug/m3. When this worker standard is used (even with the addition of background acrolein levels as in CURE's analysis), the construction-related hazard index would be 0.76, validating staff's and the applicant's finding of insignificant effects with respect to potential worker exposure to construction-related emissions. CURE's failure to appropriately distinguish between worker exposure standards and public exposure limits is an issue of continuing concern to staff who, as noted in the appendix to this analysis, will file a separate testimony to further address the issue. Moreover, arbitrarily multiplying an emission factor by ten does not represent an analytical approach that staff can support. Staff believes that these significant flaws are responsible for CURE's continuing findings of significant worker health impacts in their project analyses.

Another concern is that the background level for acrolein was reported in CURE's data as 1.4 ug/m3 ; this level was considered by CURE in all their analysis of noncancer effects. This value was obtained from limited measurements made by CURE to establish the background levels of acrolein and the other pollutants, in the area around the project site. The limited nature of CURE's measurements causes staff to doubt their reliability as background levels for the pollutants measured, as later discussed in connection with flaws in CURE's complaint about other perceived flaws in staff's analysis.

CURE (1999g, page 53) also determined from their analysis that the same acrolein-driven risk of acute effects would be significant at the nearest residences located about 1.3 miles to the north of the project site. According to information presented in the AFC as an appendix to their **Air Quality** section, the pollutant concentration at these residences would be 36 times lower than the maximum levels calculated for the project site, and used in assessing the maximum potential for acute impacts. When one corrects for this exposure diminution, CURE's upward adjustment of acrolein emission factors, and staff's proposed mitigation requiring the use of oxidizing soot filters (as described later), CURE's finding of significant acute impacts would be is incorrect with regard to such residents. While acrolein may be emitted from the proposed project at relatively insignificant levels, CURE's measured background value of 1.4 ug/m3 suggest that background acrolein presently poses a significant risk in the project area. Since acrolein will usually constitute a basin-wide problem in area of detectable background levels, mitigation would be basin wide and would include specific measures to minimize the contribution from new sources. The Sunrise project would therefore, not be relied upon to solve the problem by itself. The usual response in all such cases would be to ensure, through use of the best available control technology, that new sources like the Sunrise project would not contribute significantly to the problem. Staff's mitigation measure will do just that.

The possible existence of acrolein as a basin-wide problem, instead of a problem from oil field emissions as CURE asserts (CURE 1999g, pages 49 and 50), can be surmised from CURE's own data. We note in this regard that the background levels of acrolein was reported by CURE (1999h, page 4) as 0.62 parts per billion (ppb) for measurements made on August 28, 1999 within the Midway-Sunset oil fields. A much lower value of 0.28 ppb was reported for the relatively pristine Lokern Natural Area. For similar measurements on August 31, 1999, CURE reported a concentration of 0.33 ppb for the Midway-Sunset oil fields while a much higher value of 0.60 ppb was reported for the Lokern Natural Area. If the present oil field operations were mostly responsible for background acrolein levels, measured values would have been consistently higher in the oil field area. This finding points to background levels as resulting from basin-wide dispersion as typical of basin-wide pollution problems. The same detection pattern was reported by CURE for benzene,(which, like acrolein is mostly associated with vehicular emissions in area without large stationary sources), further pointing to a possible link to vehicular emissions. The occurrence pattern for benzene and acrolein in the project area contrasts with that for hydrogen sulfide from with the Midway Sunset oil fields. As summarized by CURE (1999j page 10), hydrogen sulfide levels measured on September 1, 1999 ranged from 20 to 80 ppb during full operations in the oil fields, but were consistently below 9 ppb in the Lokern Natural Area, clearly identifying the oil fields as the major source. Such an oil field connection cannot be reliably established at the present for acrolein, from CURE's data.

To minimize particulate emissions from construction equipment and vehicles, our Air Quality staff recommended that the Commission require them to be equipped with soot filters during use at the project site. The effectiveness of such filters was noted by CURE (1999g page 40) in their discussion of mitigation possible mitigation approaches. As more fully discussed in the **Air Quality** section, such filters can reduce the emission of aldehydes (of which acrolein is a part) by up to 90%. Staff considers this requirement as adequate to reduce the contribution of the Sunrise project to any area acrolein problem. We do not consider it necessary to further require the use of controls like catalytic converters as called for by CURE (1999g page 40).

FLAWS IN CURE'S CONCLUSIONS ABOUT STAFF'S VIEWS ON PROPER CONSIDERATION OF BACKGROUND POLLUTANTS

As previously noted, CURE (1999g, page 49) challenges staff's method of considering background pollutants. CURE asserts in this regard that most pollutants they consider significant with respect to the Sunrise project, can, and should be measured in the project area as part of normal emissions from oil field operations. We disagree with CURE and believe that such pollutants would not be found in significant amounts in the project area, and that measuring the large number of pollutants involved, in assessing the impacts of the relatively few pollutants of significance with respect to a project like Sunrise, would cause a delay and not provide additional useful information. Staff notes that of the 62 pollutants measured for by CURE in the project area, only 11 were detectable under the measurement conditions involved. As with acrolein, these pollutants were detected at levels below one part per billion. Among them, only benzene and formaldehyde are considered as posing a potentially significant health hazard by staff with respect to project like Sunrise; benzene because of its status as an established human carcinogen and formaldehyde because of its status as a sensitizing agent. Staff considers most such pollutants as incapable of significant health impacts at their normal background levels in areas without major sources which this project is not

Staff particularly notes that formaldehyde (which CURE cites along with acrolein as particularly important with respect to the Sunrise project), was not detected in the measurements made of background levels. As staff noted in the discussions on the choice of emission factors, acrolein, and formaldehyde should be emitted in specific ratios from most common sources. Staff believes this failure to detect, either indicates a flaw in the measurement procedure, or flaws in CURE's assumptions about the relative emissions of acrolein from known sources.

In their analysis, CURE considered acrolein and five other pollutants (benzene, formaldehyde, styrene toluene, and xylene) as potentially significant with respect to construction-related emissions (CURE, 1999g page 55). Background benzene was detected by CURE at the very low levels of 0.22 ug/m3 and 78 ug/m3. For styrene toluene and xylene, which were not detected, CURE assumed background levels of one-half of detection limits for their analysis. As previously noted, CURE reported the total acute hazard index for all six pollutants as 302.8, with 302 derived for acrolein alone. The 0.8 value for the other five suggests that they would not constitute a health hazard in the project area as staff would expect, pointing to the appropriateness of staff policy of not requiring the measurement of the background concentrations of such pollutants. CURE is wrong in assuming that staff did not factor the potential significance of background pollutants in our analysis. We do not require such measurements for this and similar project, because we do not expect these pollutants to be found at significant background levels. Staff's policy of not calling for specific measurements should not be interpreted as a lack of concern for their potential impacts, but as a sound professional judgement based on the specific facts of this case.

IMPACTS FROM ROUTINE PROJECT OPERATION

To assess the direct impacts of the proposed Sunrise project, the applicant conducted a health risk assessment for its pollutants as emitted from turbines during routine operations. This assessment was conducted according to procedures specified in the 1993 California Air Pollution Control Officer's Association (CAPCOA) guidelines for sources of this type. Results of this assessment were been provided to staff, along with documentation of the assumptions used (SCPP 1998a pages 8.6-6 through 8.6-16). Such documentation was provided with regard to the following:

- Pollutants considered;
- Emission levels assumed for the pollutants involved;
- Dispersion modeling used to estimate potential exposure levels;
- Exposure pathways considered;
- The cancer risk estimation process;
- Hazard index calculation; and
- Characterization of project-related risk estimates

Staff found these assumptions to be generally accurate and concurs with the applicant's findings with regard to the project-related numerical health risk estimates expressed, either in terms of the hazard index for each noncarcinogenic pollutant, or a cancer risk for estimated levels of the carcinogenic pollutants. The analysis was conducted to determine the potential for acute and chronic effects on body systems such as the liver, central nervous system, the immune system, kidneys, the reproductive system, the skin and the respiratory system.

The following pollutants were considered for potential to produce noncancer effects: ammonia, acetaldehyde, acrolein, benzene, 1,3 butadiene; formaldehyde, naphthalene, toluene, xylenes, propylene oxide and polycyclic aromatic hydrocarbons (PAHs). The following were considered with regard to a possible cancer risk: acetaldehyde, benzene, 1,3 butadiene, formaldehyde, PAHs and propylene oxide.

A hazard index value of 0.034 was calculated for combined chronic health effects for the individual at a location approximately 0.5 kilometers (km) southwest of the project site. A value of 0.068 was calculated for combined acute health effects for an individual at a location approximately 2.0 km from the site. These values are significantly below the 1.0 significance level suggesting that significant noncancer health effects would be unlikely during operations. The reference exposure value used for acrolein was the 2.5 ug/m3, which was applicable at the time the AFC was filed. When the new Cal/EPA value of .19 ug/m3 is used as suggested by CURE, the incremental hazard index would change from 0.04 to 0.5, causing the total index to change from 0.068 to 0.54. All these values are below 1.0 significance level suggesting that the Sunrise project will not contribute significantly to environmental pollution in the project area.

The highest combined cancer risk was estimated to be 0.3 in a million for an individual at the same location identified for the total hazard index for chronic effects. This risk was calculated using existing procedures, in which it is assumed that the individual will be exposed at the highest possible levels to all the carcinogenic pollutants from the project for 70 years. This risk value is much below staff's significance level of one in a million, suggesting that the emissions from the Sunrise project would be unlike to add significantly to the area's cancer.

While CURE, like staff, does not consider the emissions from the proposed project as posing a significant cancer risk of cancer, they concluded from their analysis that such emissions would pose a significant risk of noncancer effects CURE 1999g, page 60). We disagree, and believe that their flawed conclusion is due to flaws in the underlying analysis. We will address these flaws in pointing to the inappropriateness of their call for specific mitigation (CURE 1999g, page 61)

Flaws in CURE's Finding of Significance With Respect to Turbine Emissions

As with construction-related emissions, CURE's finding of significance is driven almost entirely by the risk for acrolein, whether considered separately as emitted from the proposed project, or assessed together with the CURE-measured area background levels. According to CURE's calculation, the acute hazard index for acrolein's acute effects at the location of maximum concentration, is11.84 while the value for acrolein and the others is 11.86. These values reflect the addition of background levels in the analysis. Eight pollutants (acetaldehyde, acrolein, ammonia, benzene, formaldehyde, propylene oxide toluene, and xylene) were assessed by CURE as the pollutants of relevance with respect to the Sunrise (CURE 1999g, page 60). Given the 11.84 acrolein value and the 0.2 value for the other pollutants, CURE's analysis can be interpreted to mean that only acrolein would be capable of significant impacts during project operations. The potential lack of significant impacts as reflected in the 0.02 value for the others and their CURE-established background levels, shows that they are (a) incapable of significant impacts as emitted from sources like the Sunrise project.

The CURE-calculated acute hazard index for project-emitted acrolein alone (at the point of maximum impact), is 4.47. Since this is more than one, it would suggest the possibility of significant impacts at these points of maximum exposure. However, after adjusting for CURE's upward adjustments for all acrolein emissions (by dividing by 10), this acute hazard index value would be reduced to 0.47 suggesting a lack of significant incremental (project-related) impacts as staff has concluded. For acrolein and the other pollutants, CURE calculated a hazard index of 4.49 at the point of maximum impacts. As with construction-related emissions, these CURE-calculated values show that pollutants other than acrolein are unlikely to be emitted at significant levels.

For chronic effects, maximum impacts were calculated by CURE for an uninhabited location near the project site. The incremental, mostly acrolein-driven total hazard index value is 72.4, while the incremental hazard index is 2.42. Since only oil field workers would be found at this location, the potential for significance should best be assessed using the applicable work place standards. When these standards are used, such emissions would be found to be insignificant. CURE (1999 page 61) concedes that the acute hazard index of 0.41 at the nearest residential location (1.3 miles away) reflects a potential lack of significant acute effects. Only by adding the existing acrolein levels would emissions be found significant. In such a case, this value would be 7.8. However, when this is corrected for flaws in CURE's acrolin emission derivation approach, this value will change to .78, which is a level of insignificance. The incremental project-related) chronic hazard index value of 0.014 is insignificant while a total chronic hazard of 70.0 is obtained when the project-specific concentration is added to the background levels. Adjusting for the noted, acrolein-related flaws in exposure derivation approach would reduce all impacts to levels of insignificance. This would support staff's conclusion that normal operations would not pose a risk significant risk of human health impacts.

Impacts of Emission Increases During Facility Start-Ups

For projects like Sunrise, the beginning of operations (start-up) would involve the sequential initiation of gas combustion in the facility. It usually takes about one hour to achieve the conditions of maximum combustion efficiency associated with steady-state emissions. Given the usually short duration of start-up conditions as well as the number of start-ups, staff does not consider these emission increases to be insignificant. This is reflected in data in the **Air Quality** section showing the differences between emissions at the initiation of combustion, and emissions during normal combustion conditions. As reflected in this data, the emissions of noncriteria pollutants in the VOC fraction would decrease from 51 lbs. per hour, per turbine, to 2.6 lbs. per hour, per turbine. Staff does not regard these emission differences as significant.

INDIRECT OPERATIONAL-PHASE IMPACTS

Operating the 700 wells to which steam will be supplied from the proposed Sunrise project would cause the emission of oil production-related pollutants the most important of which are hydrogen sulfide (H2S) and (VOCs), as noted by CURE (1999g, pages 56, 63 through 67). These new wells will be within ¾ miles of the project site.

POTENTIAL IMPACTS FROM WELL DRILLING

The equipment to be used for well construction are identified in the **Air Quality** section along with expected emission levels. Given the proximity of these wells to the proposed Sunrise project, and the short-term nature of such construction, staff expects any impacts of such emissions to be confined to the oil field area which are generally inaccessible to the general public. Using the worker exposure standards (which are appropriate for such exposure situations) shows that such emissions would not produce effects in humans. CURE's finding of potentially significance impact are due to the flaws in their assessment approach as discussed in connection with construction-related emissions. Since staff regards their findings as flawed, we do not support their call (CURE 1999g, page 59) for well drilling-specific mitigation.

POTENTIAL IMPACTS FROM WELL OPERATIONS

The pollution-related impacts of concern with respect to well operations are those from VOC and hydrogen sulfide (H2S) emissions. Staff did not consider well operation as posing a significant health hazard given that their scheduled operations are subject to Air District rules that minimize emission from such wells. As a result, staff did not consider it necessary to propose specific conditions of certification to further minimize impacts. CURE disagrees with staff's conclusions. They believe that these emissions are potential health significance, hence their call for specific mitigation. We believe that CURE's finding is incorrect an do not support their call for a level of mitigation higher than specified in the **Air Quality** and **Biological Resources** sections respect to human and wildlife impacts at issue.

In their analysis, CURE (1999g, pages 63 through 67), estimated the potential cancer risk from such well operations at 6.01 in a million for the point of maximum exposure. Since there are no residences at this location, it would be inappropriate to calculate a cancer risk for such exposures. CURE is also incorrect in adding the background benzene concentration of 0.70 ug/m3 to their modeled, (well-specific) exposure level of .21 ug/m3, in obtaining the incremental cancer risk. Since this well-specific level is 23% of the total concentration, the correct operations related cancer risk estimate should be 23% of the 6.1 in a million value calculated. Since, as previously noted, the pollutant concentration at the nearest residence would be lower than at the point of maximum exposure by a factor of 36, the appropriate cancer risk, even using CURE's own exposure estimates, should be 0.038 in a million, a number significantly below the 1 in a million significance level.

As discussed earlier, it is inappropriate for CURE to use the reference exposure levels in assessing the potential for health impacts at the project site where only oil field worker would be encountered. Since CURE's data shows that hydrogen sulfide alone is responsible for the potential risk of health impacts, the assessment for impacts should have been made using the appropriate worker standard of 150 ug/m3. When this standard is used, CURE's finding of a potentially significant acute health impact would be shown to be incorrect. Given the previously noted 36-fold reduction in exposure at the nearest residence (as compared to the calculated, maximum exposure level at the project site), the calculated hazard index should have been reduced by a factor of 36. After such reduction, this is done, the calculated value of 2.89 would change to .08, pointing to a potential lack of effects. The hazard index values for the other pollutants (benzene, toluene, and xylene that CURE considered (using the inappropriate public-specific, reference exposure limits) point to a potential lack of effects. When the appropriate worker standards are used, such a finding would be more pronounced.

CURE has asked for more stringent control of H2S from these wells because of their contention that significant health impacts are possible in humans and wildlife at its parts per billion levels of occurrence in the project area ,as established from CURE's own measurements (CURE 1999g page 10). This contention is not supported by the available evidence. As discussed in the **Biological Resources** section (in connection with effects on wildlife), the naturally-occurring hydrogen sulfide is a well established eye and respiratory whose presence can be detected by smell at levels starting from the parts per billion range. Since the sense of smell can be dulled after prolonged exposure, detection by smell should not be relied upon to avoid health impacts. It is for this reason that H2S monitors are presently required at the Midway-Sunset oil for areas of possible pockets of accumulation. Smelling the gas under normal conditions will usually call for immediate mitigation, thereby limiting long-term exposures to relatively low levels.

There is significant uncertainty among researchers about the ability of H2S to produce significant health impacts at its normally low environmental levels. In the testimony by CURE, (1999k) the possibility of such impacts was proposed from theoretical consideration of the underlying biological mechanisms. The results of limited studies in the Midway-Sunset oil fields were further presented as reliable evidence for significant effects at low levels, with respect to wildlife presently inhabiting the project site. Staff does not regard such evidence as adequate for such conclusions, nor do we regard it as adequate to support CURE's present level of concern about potential emissions from the project-related oil wells. Such concern is the reason behind CURE's call for more stringent controls.

While it is possible that H2S could accumulate in underground such as dens and burrows, to levels capable of the effects that CURE addressed, preliminary Commission staff measurements, as discussed in the **Biological Resources** section, detected H2S at levels significantly below 1 ppm, making it premature to link the effects to with H2S exposure. What is clear from the available evidence is the need for continued H2S controls from identifiable source. The continuing challenge is to ensure that any related measures would be at levels justified by the magnitude of the risk involved. Staff believes that CURE's concern about the impacts of normal H2S exposure is more than the evidence suggests. We note for instance that H2S can be detoxified in the body and excreted mainly through the kidney and the colon, reflecting the body's ability to compensate, to some degree for effects at the cellular level. Not every exposure to a toxicant is able to produce significant health effects. We note in this regard, that the EPA does not presently regulate the levels of H2S in drinking water, since the water levels of potential health significance would render the water unpalatable. This EPA stance reflects the fact that toxic effects are not expected at every exposure level. The same principle should apply to H2S at the low (parts per billion levels) at issue with respect to the Sunrise project.

As noted by our Air Quality staff, the rules of the Air District require a 99.9% control for VOC emissions from new wells. Such controls are also effective for the co-emitted VOC. Staff's calculation shows that by the year 2010, the VOCs from the 700 new wells would represent approximately 0.45% of VOC emissions associated with oil production in the project area. Therefore, staff does not expect these wells to contribute significantly to existing VOC and H2S levels in the project area.

CUMULATIVE IMPACTS

In addition to the Sunrise project, the Commission is reviewing the Elk Hills and La Paloma power plant projects, which are proposed for the same western Kern County area. The three projects, all of which will burn natural gas, intend to use the same state-of-the art pollution controls as currently available. They are to be located about 8 miles apart. Staff has reviewed the potential public health impacts from each of these projects to determine the potential cumulative impacts that could result from their combined operation.

When toxic pollutants are emitted from multiple sources within a given area, the cumulative, or additive, impacts of such emissions could, in concept, lead to significant health impacts within the population, even when such pollutants are emitted at insignificant levels from the individual sources involved. Experience has shown, however, that the peak impacts of such toxic pollutants are normally localized within relatively short distances from the source. Toxic pollutant emission levels beyond the point of maximum impact normally fall within existing ambient background levels. Potentially significant cumulative impacts are only expected in situations where new sources are located adjacent to one other. The highest impact levels, from each of the three projects being evaluated, are approximately one mile or less from the emissions source. Therefore, given the approximate 8-mile distance between each of the projects, their combined operation will not cause or contribute significantly to a public health impact from toxic pollutant emissions.

FACILITY CLOSURE

According to information from the applicant (SCPP 1998 pages 4-1 through 4-3), the Sunrise project is planned to operate for 20 years. Any cessation of operations could be temporary or permanent.. A permanent closure would mean the end of operations with no plans to restart operations. A temporary closure would result in cessation of operations with the intent to restart. No emissions would occur during closures meaning that no pollutant exposures would occur. When the facility is permanently closed steps would be taken to ensure the all facility components are dismantled and disposed of as the law requires

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Staff has determined that the construction and operation of the proposed natural gas-burning project will not pose a significant public health risk to humans with respect to the pollutants considered, provided the project complies with SJVUAPCD rules related to (1) the control of construction-related emissions, (2) emissions from the project's turbines and (3) emissions from oil field operations and. CURE's concern about the project is due to their view of potential hazards from acrolein and H2S. We consider this concern to be more than justified by the available evidence and do not support their call for mitigation above levels specified by staff in the **Air Quality, Biological Resources,** and the **Worker Safety and Fire Protection** sections.

RECOMMENDATIONS

Since no significant public health impacts are considered likely by staff for the Sunrise project as proposed, no Public Health Conditions of Certification are proposed.

REFERENCES

Agency for Toxic Substances and Disease Registry. Toxicological Profile for Acrolein. U.S Department of Health and Human Serviced, Atlanta Georgia.

California Air Resources Board (CARB) 1996. California Toxic Emissions Factors (CATEF) Database for Natural Gas-Fired Combustion Turbine Cogeneration.

California Union for Reliable Energy. (CURE) September 3, 1999 Comments on the Sunrise Preliminary Staff Assessment. Pages 1 through 68.

CURE, 1999. Testimony of D. Michael Fry on Behalf of California Unions For Reliable Energy on Biological Impacts of the Sunrise Cogeneration and Power Project. October 15, 1999.

CURE 1999. Testimony of Phyllis Fox on Behalf of the California Unions for Reliable Energy on Traffic and Transportation Impacts and Worker Safety Impacts of the Sunrise Cogeneration Project.

California Air Pollution Control Officers Association (CAPCOA) 1993. Air Toxics "Hot Spots" Program, Revised 1992 Risk Assessment Guidelines. Prepared by the Toxics Committee, October 1993.

National Institute of Occupational Safety and Health (NIOSH) 1994 NIOSH Pocket Guide to Chemical Hazards 397p

Sunrise Cogeneration and Power Project 1998. Application for Certification, Sunrise Cogeneration and Power Project (98-AFC-4). Submitted to the California Energy Commission, December 21, 1998

APPENDIX A
Screening Level Risk Assessment
Construction Impacts

This screening level health risk assessment is provided to address concerns raised by CURE regarding risks to both the public and oil field workers potentially exposed to construction emissions associated with grading of the site. Specifically, CURE has raised concerns regarding the levels of arsenic and chromium in soils at the site identified in the Phase II site assessment (Dames and Moore 1999). The maximum concentration of arsenic measured in soils during the Phase II assessment was 12.8 mg/Kg and the maximum concentration of chromium in soils at the site was 24.4 mg/Kg. CURE has argued that oil field workers should be evaluated as if they were public receptors and that a health risk assessment be conducted to evaluate the potential for health impacts on workers. Staff does not believe it is appropriate to evaluate the potential health risks to workers using the same methods and assumptions typically used to evaluate public health risks. Staff plans to file testimony addressing this issue on January 3. However, staff conducted this analysis to demonstrate that even if methods applicable to evaluating public exposure are used to assess worker impacts, CURE's claim of significant worker risk is grossly exaggerated.

To assess the potential worst case health risks associated with exposure to fugitive dust resulting from construction activities, staff used modeling results of maximum PM10 impacts provided in Air Quality Table 9. These results indicate a maximum annual PM10 concentration of 9.3 ug/ M^3 at the point of maximum impact about 145 meters south west of the site. To simplify the analysis staff assumed that the PM10 impacts are from soil with maximum concentrations of arsenic and chromium as indicated by the Phase II assessment. For the purpose of evaluating potential public health impact, staff assumed that the maximally exposed receptor would be present at the location of maximum PM10 concentration 24 hours a day for 70 years. This is consistent with the derivation of the ambient air Preliminary Redemption Guidelines (PRGs) which are ambient concentrations associated with a lifetime cancer risk of 1 in 1,000,000 (U.S. E.P.A. Region 9, 1999). However, the nearest residence is located more than a mile from the site where as the maximum construction impacts occur within 145 meters of the site. This residence is the nearest location where the assumption of continuous exposure would be appropriate. From air quality modeling in Appendix B of the AFC the annual average PM10 concentration at the nearest residence is .05536 ug/M3. This is 168 times less than the concentration at the maximum impact location.

To evaluate the potential exposure of workers it is first necessary to estimate an equivalent continuous lifetime average exposure, consistent with public exposure, but based on the 40 hours per week over one year. Staff made the conservative simplifying assumption that a maximally exposed worker would be continuously present at the point of maximum annual impact during all 40 hours a week, every day, for a period of one year. Staff estimated an equivalent maximum worker lifetime exposure by multiplying the maximum PM10 exposure by (40x52)/(24x365) to reflect a 40-hour workweek as opposed to 24 hour a day continuous exposure.

Staff then divided by 70 to reflect one year of exposure as opposed to a 70-year lifetime exposure. These corrections are necessary because the Preliminary Remediation Guidelines (PRGs) used as the exposure criteria are based on the continuous exposure over 70 years that would produce a maximum cancer risk of 1 in 1,000,000. Both the assumed exposure regimen and the modeling of maximum annual average ambient concentrations are very conservative and significantly overestimate the actual risk.

Based on this analysis staff estimated a maximum annual average ambient arsenic concentration of .00012 ug/M^3 (9.3X12.8X10-6) at the point of maximum impact and that the potential maximum equivalent lifetime exposure of an oilfield worker would be .00000040 ug/M^3 (.00012X(40x52)/(24x365)/70). The maximum annual average arsenic concentration at the nearest residence is .00000071ug/M^3 (.00012/168). These estimates are conservative and are also far lower than the PRG for arsenic of .00045 ug/M^3. The worker exposure is yet several more orders of magnitude further below the applicable work place standard of .01 mg/M^3 (10 ug/ M^3) (NIOSH 1994). Using this same approach for chromium, results in an annual average chromium concentration of .00024 ug/M^3 at the point of maximum impact and a potential maximum equivalent lifetime worker exposure of .00000076 ug/M^3. The estimated maximum annual average chromium concentration at the nearest residence is .0000014 ug/M^3. Again, the potential worker exposure would be far below the ambient air PRG of .00016 ug/M^3. It is also yet several more orders of magnitude further below the applicable workplace standard of .5 mg/M^3 (500 ug/M^3) (NIOSH 1994). The maximum annual average chromium concentration at the nearest residence is also far below the .00021 ug/M^3 PRG. Thus, staff concludes that construction activities will not result in significant risk to either the public or to oil field workers.

BIOLOGICAL RESOURCES

Testimony of Rick York and Linda Spiegel

INTRODUCTION

This section provides the Energy Commission staff's analysis of potential impacts to biological resources from the construction and operation of the Sunrise Cogeneration and Power Company's (SCPC) Sunrise Cogeneration and Power Project (SCPP). This analysis addresses potential impacts to state and federally listed species, species of special concern, wetlands, and other areas of critical biological concern. This analysis also describes the biological resources of the project site and at the locations of appurtenant facilities. It also determines the need for mitigation, the adequacy of mitigation proposed by the applicant, and where necessary, specifies additional mitigation measures to reduce identified impacts to less than significant levels. It also determines compliance with applicable laws, ordinances, regulations and standards (LORS), and recommends conditions of certification.

This analysis is based, in part, upon information provided in the Sunrise Application for Certification (AFC) (SCPP 1998a), workshops, staff data requests and applicant responses (SCPP 1999d and SCPP 1999n) site visits, and discussions with various agency representatives.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS

FEDERAL

ENDANGERED SPECIES ACT OF 1973

Title 16, United States Code, section 1531 et seq., and Title 50, Code of Federal Regulations, part 17.1 et seq., designate and provide for protection of threatened and endangered plant and animal species, and their critical habitat.

MIGRATORY BIRD TREATY ACT

Title 16, United States Code, sections 703 - 712, prohibits the take of migratory birds.

STATE

CALIFORNIA ENDANGERED SPECIES ACT OF 1984

Fish and Game Code sections 2050 et seq. protects California's rare, threatened, and endangered species.

NEST OR EGGS – TAKE, POSSESS, OR DESTROY

Fish and Game Code section 3503 protects California's birds by making it unlawful to take, possess, or needlessly destroy the nest or eggs or any bird.

BIRDS OF PREY OR EGGS – TAKE, POSSESS, OR DESTROY

Fish and Game Code section 3503.5 protects California's birds of prey and their eggs by making it unlawful to take, possess, or destroy any birds of prey or to take, possess, or destroy the nest or eggs of any such bird.

MIGRATORY BIRDS – TAKE OR POSSESSION

Fish and Game Code section 3513 protects California's migratory birds by making it unlawful to take or possess any migratory nongame bird as designated in the Migratory Bird Treaty Act or any part of such migratory nongame bird.

FULLY PROTECTED SPECIES

Fish and Game Code sections 3511, 4700, 5050, and 5515 prohibits take of animals that are classified as Fully Protected in California.

SIGNIFICANT NATURAL AREAS

Fish and Game Code section 1930 et seq. designates certain areas such as refuges, natural sloughs, riparian areas and vernal pools as significant wildlife habitat.

STREAMBED ALTERATION AGREEMENT

Fish and Game Code section 1600 et seq. requires CDFG to review project impacts to waterways, including impacts to vegetation and wildlife from sediment, diversions and other disturbances.

NATIVE PLANT PROTECTION ACT OF 1977

Fish and Game Code section 1900 et seq. designates state rare, threatened, and endangered plants.

CALIFORNIA CODE OF REGULATIONS

Title 14, sections 670.2 and 670.5 list animals of California designated as threatened or endangered.

LOCAL

KERN COUNTY GENERAL PLAN LAND USE, OPEN SPACE, AND CONSERVATION ELEMENTS OF 1994

SECTION 8, RESOURCES

Policy 14: Habitats of threatened and endangered species should be protected to the greatest extent possible.

KERN COUNTY GENERAL PLAN ENERGY ELEMENT OF 1990

PART 1 - ISSUES, GOALS, POLICIES, AND IMPLEMENTATION

Policy 12: The County should work closely with local, state, and federal agencies to assure that all projects, both discretionary and ministerial, avoid or minimize direct impacts to fish, wildlife and botanical resources, whenever practical.

Policy 13: The County should develop and implement measures which result in long-term compensation for wildlife habitat which is unavoidably damaged by energy exploration and development activities.

SETTING

REGIONAL DESCRIPTION

The proposed SCPP site is to be located on approximately 20 acres within the Midway-Sunset Oil Field, approximately 3 miles northwest of Fellows, California, in western Kern County.

The predominant vegetation type found in the project vicinity is valley saltbush scrub which is dominated by common saltbush (Atriplex polycarpa), spiny saltbush (A. spinifera), pale-leaf goldenbush (Isocoma acradenia var. bracteata), and a variety of non-native, annual grasses such as brome (Bromus spp.), foxtail (Hordeum spp.), and vulpia (Vulpia spp.). Other species found in the project area include native annual spring-flowering annuals such as white layia (Layia glandulosa) and bird's eye gilia (Gilia tricolor). Other native shrub species found in the project area include matchweed (Gutierrezia californica) and bladderpod (Isomeris arborea).

Also distributed throughout the entire project area are non-native grasslands. This vegetation type is dominated by non-native annual grasses such as brome, foxtail, and vulpia, with several species of spring-flowering, annual forbs such as gilia, lupine (Lupinus spp.), fiddleneck (Amsinckia spp.), filaree (Erodium cicutarium), and owl's-clover (Castilleja spp.).

The valley saltbush scrub and annual grasslands of western Kern County are home to a wide variety of birds, mammals, and reptiles. Common bird species include red-tailed hawks (Buteo jamaicensis) and western meadowlarks (Sturnella neglecta). Mammals often present include black-tailed hare (Lepus californicus), kangaroo rats (Dipodomys spp.), deer mouse (Peromyscus maniculatus), coyote (Canis latrans), bobcat (Felis rufus), and American badger (Taxidae taxus). Common amphibians and reptiles found in the region include western toad (Bufo boreus), side-blotched lizard (Uta stansburiana), western whiptail (Cnemidophorus tigris), western rattlesnake (Crotalus viridis), and gopher snake (Pituiphis melanoleucus).

A wide variety of sensitive species are also known to occur in the project vicinity. Sensitive species are species that are either state or federally listed as rare, threatened, or endangered, or are state listed as Fully Protected, or state or federally identified as a Species of Special Concern, or a plant species identified in the California Native Plant Society's Inventory of Rare and Endangered Vascular Plants of California (CNPS 1994) or the California Natural Diversity Special Plants List (California Department of Fish and Game 1999). Sensitive species including the San Joaquin kit fox (Vulpes macrotis mutica), giant kangaroo rat (Dipodomys ingens), San Joaquin antelope squirrel (Ammospermophilus nelsoni), blunt-nosed leopard lizard (Gambelia sila), Swainson's hawk (Buteo swainsoni), golden eagle (Aquila chrysaetos), California condor (Gymnogyps californianus), burrowing owl (Athene cunicularia), California jewelflower (Caulanthus californicus), Kern mallow (Eremalche kernensis), and Hoover's eriastrum (Eriastrum hooveri) are found in western Kern County.

For complete lists of vascular plants and wildlife seen while completing field surveys for the SCPP biological assessment, refer to Tables 8.2-9 and 8.2-10 respectively found in the Biological Resources section of the AFC (SCPP 1998a).

Refer to BIOLOGICAL RESOURCES Table 1 for a complete list of the sensitive biological resources associated with the region of the proposed project. Please see the Project Description section of this document for a more detailed description of the project site and setting.

SITE VICINITY DESCRIPTION

The SCPP will be located on a 16-acre site within a 20-acre parcel within the Midway-Sunset Oil Field. A complete list of plants and animal species seen during 1998 and 1999 field surveys completed for all proposed Sunrise project appurtenant facility can be found in AFC Appendix C - Biological Resources Assessment, Table 8.2-9, 10, & 11 (SCPP 1998a). The project is proposed for a region of California that contains many sensitive species, and Biological Resources Table 1 identifies those sensitive species:

BIOLOGICAL RESOURCES Table 1
- Sensitive Species -

Sensitive Plants	Status*
Forked fiddleneck (Amsinckia vernicosa var. furcata)	CNPS List 1B
California jewelflower (Caulanthus californicus)	CNPS List 1B/FE/SE
Slough thistle (Cirsium crassicaule)	CNPS List 1B
Gypsum-loving larkspur (Delphinium gypsophilum ssp. gypsophilum)	CNPS List 4
Recurved larkspur (Delphinium recurvatum)	CNPS List 1B
Hoover's eriastrum (Eriastrum hooveri)	CNPS List 1B/FT
Cottony buckwheat (Eriogonum gossypinum)	CNPS List 1B
Tejon poppy (Eschscholzia lemmonii ssp. kernensis)	CNPS List 1B
Kern mallow (Eremalche parryi ssp. kernensis)	CNPS List 1B/FE
Hollisteria (Hollisteria lanata)	CNPS List 1B
San Joaquin wooly threads (Lembertia congdonii)	CNPS List 1B/FE
Oil neststraw (Stylocline citroleum)	CNPS List 1B

Sensitive Wildlife	Status*
Tricolored blackbird (Agelaius tricolor)	SSC
LeConte's thrasher (Toxostoma lecontei macmillanorum)	SSC
California condor (Gymnogyps californianus)	SE/FE
Golden eagle (Aquila chrysaetos)	SC
Swainson's hawk (Buteo swainsoni)	ST
Long-eared owl (Asio otus)	SSC
Burrowing owl (Athene cunicularia)	SSC
Northern harrier (Circus cyaneus)	SSC
Yellow warbler (Dendroica petechia)	SSC
White-tailed kite (Elanus caeruleus)	FP
California horned lark (Eremophila alpestris actia)	SSC
Prairie falcon (Falco mexicanus)	SSC
Loggerhead shrike (Lanius ludovicianus)	SSC
Blunt-nosed leopard lizard (Gambelia sila)	SE/FE/FP
San Joaquin coachwhip (Masticophis flagellum ruddocki)	SSC
Western spadefoot toad (Scaphiopus hammondii hammondii)	SSC
Giant kangaroo rat (Dipodomys ingens)	SE/FE
Short-nosed kangaroo rat (Dipodomys nitratoides brevinasus)	SSC
Tulare grasshopper mouse (Onychomys torridus tularensis)	SSC
San Joaquin pocket mouse (Perognathus inornatus inornatus)	SSC
San Joaquin antelope squirrel (Ammospermophilus nelsoni)	ST
San Joaquin kit fox (Vulpes macrotis mutica)	ST/FE
American badger (Taxidea taxus)	SSC
Longhorn fairy shrimp (Branchinecta longiantenna)	FE
Vernal pool fairy shrimp (Branchinecta lynchi)	FE
Vernal pool tadpole shrimp (Lepidurus packardi)	FT

* Status legend: CNPS List 1B = Plants rare or endangered in California and elsewhere (California Native Plant Society 1994), CNPS List 4 = Plants of Limited Distribution; SSC = Species of Special Concern (CDFG 1992), FE = Federally listed Endangered, FT = Federally listed Threatened, SE = State listed Endangered; ST = State listed Threatened and FP = State Fully Protected.

POWER PLANT SITE, LAYDOWN AREA & SUNRISE SWITCHYARD

The SCPP area contains a mixture of annual grasslands and some saltbush shrubs (Atriplex spp.). The power plant site and the surrounding region has a long history of oil development as evidenced by the presence of oil production wells, steam generators and steam lines and other oil field related facilities found in the project vicinity.

The annual grasslands and saltbush scrub vegetation types found in the vicinity of proposed power plant, laydown, and new Sunrise switching station is potential habitat for a variety of sensitive species including the San Joaquin kit fox, blunt-nosed leopard lizard, and the San Joaquin antelope squirrel. Construction of the power plant and use of the laydown area will permanently impact 12.4 acres and temporarily impact 13.8 acres. Construction of the Sunrise switching station will permanently impact 3.2 acres of annual grassland habitat.

TRANSMISSION LINE ALTERNATIVES

Route A, the original transmission line route identified in the AFC, was proposed to travel due east where it would connect with an existing transmission line at a new substation, the Valley Acres substation. At the Valley Acres substation the transmission line would tie into the existing 230 kV California Department of Water Resources (CDWR) transmission line and travel in a northerly direction and terminate at the PG&E Midway substation near Buttonwillow. On May 21, 1999, SCPC filed supplemental testimony (SCPP 1999k) that indicated that additional routes (Routes B, D, E, F) were being considered since the CDWR line did not appear to be available to SCPC on acceptable commercial terms. As a result, SCPC does not consider Route A to be the preferred transmission line interconnection route.

Since Route A is no longer a viable option, the preferred transmission line route is Route B. Route B would connect the SCPP directly to the PG&E Midway substation near Buttonwillow. Route B actually represents a corridor with three alternatives (Routes D, E, and F) utilizing what is identified as the Route B corridor. The alternatives consist of consolidating one or more transmission lines planned by other developers with the SCPP transmission line. Route D would connect the SCPP to a future Midway-Sunset Cogeneration Project (MSCC) switchyard, and then would connect MSCC and Midway with a joint-ownership transmission line. Route E would connect the SCPP and MSCC then would connect MSCC to the proposed La Paloma switchyard with a joint-ownership transmission line, and then would connect all parties to the Midway substation with a joint-ownership transmission line. Route F would connect the SCPP to the proposed La Paloma switchyard, and then would connect La Paloma and Midway with a joint-ownership transmission line.

Construction of any of the possible transmission line options has the potential to impact several sensitive species including the San Joaquin kit fox, blunt-nosed leopard lizard, San Joaquin antelope squirrel, various listed kangaroo rat species, and several sensitive plant species.

Along the transmission line corridor many seasonally wet depressions are known to occur. These depressions are not classified as vernal pools; however they may contain federally listed invertebrate species including the longhorn fairy shrimp (Branchinecta longiantenna), the vernal pool fairy shrimp (Branchinecta lynchi), and the vernal pool tadpole shrimp (Lepidurus packardi).

Field surveys for these species were completed for the La Paloma power plant project (98-AFC-2) during the spring of 1999 for the La Paloma transmission line route, and only the versatile fairy shrimp (Branchinecta lindahli), a common, non-federally listed fairy shrimp species, was found (Arnold 1999). The SCPP transmission line Route B corridor includes the proposed La Paloma project transmission line route, so staff expects that the same common, non-listed species will be found associated with the SCPP Route B corridor.

As of June 30, 1999 (SCPP 1999k), the SCPP would, in the worst case (Route B), permanently impact 6.9 acres of privately owned habitat, temporarily impact 14.2 acres, temporarily impact 1.3 acres of conserved habitat, and permanently impact 3.5 acres of conserved habitat. These acreage impacts would be significantly lower if alternatives (Routes D, E, and F) are developed.

The Route B corridor crosses a 44,000-acre habitat conservation planning area identified as the Lokern Natural Area. The Lokern Natural Area contains two protected areas, the Lokern Preserve managed by the Center for Natural Lands Management (CNLM), a private habitat conservation organization, and the Lokern Ecological Reserve managed by the California Department of Fish and Game (CDFG). The Lokern Natural Area was first established as a high priority area for habitat conservation since it represents a rather large area of undisturbed habitat, which is home for the sensitive species known to occur in the region. Representatives of several public agencies and private landowners, including the Energy Commission, the Bureau of Land Management (BLM), CDFG, the U. S. Fish and Wildlife Service (USFWS), and CNLM work cooperatively as the Lokern Cooperative Group to protect and manage the publicly and privately owned lands within the Lokern Natural Area. Since there is extensive energy development in the region of the Lokern Natural Area, the Energy Commission is a signatory of the Memorandum-of-Understanding developed to help guide the management of the habitat contained in the Lokern Natural Area.

NATURAL GAS SUPPLY PIPELINE CORRIDOR

The natural gas supply pipeline for the proposed power plant will be roughly 60 feet long, and will tie into the existing Texaco California Inc. Main Utility Corridor. Construction of the SCPP natural gas pipeline will permanently impact 0.07 acres of saltbush scrub habitat. Loss of this habitat will affect sensitive species such as the San Joaquin kit fox and the blunt-nosed leopard lizard.

STEAM, FEEDWATER, FRESHWATER AND WASTEWATER PIPELINES

Since the SCPP will provide steam to enhance oil recovery efforts in the adjacent Midway-Sunset Oil Field, water and steam will be distributed in the immediate vicinity of the power plant. Construction of the steam, feedwater, and wastewater pipelines associated with the power plant will impact 1.4 acres of annual grassland habitat. In addition, construction of the freshwater supply pipeline will permanently impact 0.07 acres of annual grassland habitat. Loss of this habitat will affect sensitive species such as the San Joaquin kit fox, San Joaquin antelope squirrel, and the blunt-nosed leopard lizard.

ACCESS ROAD IMPROVEMENTS FOR POWER PLANT AND SWITCHYARD

Power plant and switching station access roads need to be constructed and improved which will result in the permanent loss of 3.5 acres of grassland habitat. Constructions of these access roads will permanently impact habitat utilized by sensitive species including the San Joaquin kit fox, the blunt-nosed leopard lizard, and the San Joaquin antelope squirrel.

NEW OIL PRODUCTION WELLS, STEAM INJECTION WELLS, STEAM LINES, IMPROVEMENTS TO THE PRODUCED WATER TREATMENT FACILITY & DIRT ACCESS ROADS

The SCPP power plant will produce approximately 120,000 barrels of steam per day for enhanced oil recovery in the Midway-Sunset oil field. This amount of steam is sufficient for roughly 2000 oil production wells and associated steam injection wells. Within the ¾-mile radius circle around the proposed power plant, which staff considers to be the sphere of influence of the steam produced by the power plant, roughly two-thirds (1300 wells) of the oil production wells and steam injection wells currently exist. In addition to these existing oil production wells and steam injection wells, roughly one-third (700 wells) will be new and are expected to be constructed.

Construction of these new oil production wells, steam injection lines and wells, and associated dirt access roads represent significant indirect impacts attributable to the SCPP. SCPC has provided information (SCPP 1999n) that helped staff calculate the amount of acreage (176.4 acres) that is expected to be permanently impacted as a result of the indirect impacts associated with the SCPP. This loss of habitat has the potential to affect sensitive species such as the San Joaquin kit fox, the blunt-nosed leopard lizard, and the San Joaquin antelope squirrel.

Improvements to the existing produced water treatment facilities will be necessary for the SCPP, however all improvements will occur within the existing 10-acre produced water treatment facility, so no new disturbance of additional habitat will occur (SCPP 1999n).

IMPACTS

PROJECT SPECIFIC DIRECT AND INDIRECT IMPACTS

In the CEQA Guidelines, direct impacts are defined as those impacts that are directly attributable to the project and occur at the same time and place. Indirect impacts are caused by the project, but can occur later in time or farther removed in distance, but are still reasonably foreseeable and related to the project.

During various workshops and site visits there have been several discussions between staff, SCPC, other agencies, and interveners about project scope. Staff and SCPC have reached an agreement on the project's scope that is contained in a document identified as a joint blueprint (CEC/SCPP 1999a). This document was submitted to the Energy Commission on May 21, 1999. This joint blueprint identifies what staff and SCPC believe are the project components that may result in direct, indirect, and cumulative impacts. The Sunrise Project Committee, in an order dated June 2, 1999 (CEC 1999uu), adopted the joint blueprint as the guiding document for the project scope and associated environmental analysis.

The proposed project may directly impact a variety of sensitive species known to occur in the project vicinity. However, SCPC has proposed a variety of sensitive species mitigation measures they intend to employ to minimize or totally avoid impacting individual sensitive species. A complete list of mitigation measures and implementation methods will be completed in consultation with the CDFG, BLM, and the USFWS and will be included in the project's Biological Resources Mitigation Implementation and Monitoring Plan. For more information about specific avoidance measures, see Biological Resources Conditions of Certification **BIO-1, BIO-5, BIO-6,** and **BIO-9**.

This project may also contribute to the fragmentation of habitat in the Midway-Sunset oil field. To address this issue, the applicant has indicated (SCPP 1999n) that they will minimize impacts to habitat and protect sensitive areas, including natural drainages and riparian corridors, and will meet all state and federal regulatory requirements. The applicant also intends to implement habitat restoration measures to lessen the project's temporary impacts to wildlife habitat.

It is staff's opinion that in spite of all the oil field development that is occurring in the Midway-Sunset oil field and that which will occur as part of this project, sensitive species such as the San Joaquin kit fox will continue to utilize this very disturbed habitat for denning and foraging. The San Joaquin kit fox is currently found in the Midway-Sunset oil field, and will continue to be there after this project is constructed and is operating. Thus, staff has recommended that a variety of mitigation measures be implemented to either minimize or totally avoid impacts to the San Joaquin kit fox and other sensitive species found in the region.

Loss of sensitive species habitat is the primary concern of staff since conversion of habitat by agricultural, industrial, and urban uses have eliminated these species from the majority of their historic range (USFWS 1998). Information provided by the applicant (SCPP 1999d and 1999f) and Radian (SCPP 1999k) in June 1999 helped quantify the SCPP direct and indirect, temporary and permanent, habitat acreage impacts. The following table **(Biological Resources Table 2)** identifies the SCPP acreage impacts to wildlife habitat.

BIOLOGICAL RESOURCES Table 2

DIRECT IMPACTS ACREAGES

	Private lands (acres)		Conserved lands (acres)	
Facility	**Permanent**	**Temporary**	**Permanent**	**Temporary**
Power plant/laydown area	12.4	13.8	--	--
Sunrise switchyard	3.2	--	--	--
Steam/feed/wastewater lines	1.4	--	--	--
Freshwater pipelines	0.07	--	--	--
Natural gas pipeline	0.07	--	--	--
Access road improvement	3.5	--	--	--
Worst case t-line Route B	7.0	14.2	1.3	3.5
IMPACT ACREAGE TOTALS	**27.5**	**28.0**	**1.3**	**3.5**

INDIRECT IMPACTS ACREAGE

Facility	**Private lands (acres) Permanent Impact**
700 new oil production wells & steam injection wells, steam lines & dirt roads	176.4
IMPACT ACREAGE TOTAL	**176.4**

Staff calculated the indirect acreage impacts (176.4 acres) using the following method:

SCPC has indicated that a combination of 700 new oil production wells and steam injection wells, plus associated new dirt roads and steam lines, will be added to the existing oil field within the ¾-mile radius area surrounding the proposed power plant. 90% of these new facilities will be located in already heavily disturbed (infill) areas, and 10% will be located outside the heavily developed (step-out) area (SCPP 1999n). SCPC has provided the acreage impacts that are expected, on average, for the infill wells, the step-out wells and associated new dirt roads and steam injection lines. The applicant has identified that 0.23 acre will be permanently impacted for each new well in the infill oil field area, and 0.45 acre per new well in the step-out area.

To calculate the acreage impacts and arrive at the total for the indirect impacts to wildlife habitat, staff performed the following calculations:

For infill development -

700 wells x 90% = 630 infill wells x 0.23 acres per well = 144.9 acres

For step-out development -

700 wells x 10% = 70 step-out wells x 0.45 acres per well = 31.5 acres

Total indirect impacts acreage impacts - 144.9 acres + 31.5 acres = 176.4 acres

Neither staff nor SCPC tried to quantify the temporary indirect effects of the addition of the 700 new oil production wells, steam injector wells, and additional access roads. However, temporary indirect impacts will occur when this development occurs, so staff will propose mitigation measures (Best Management Practices and take avoidance measures) to be implemented by the project owner to help minimize impacts to sensitive species and their habitat during the construction of the 700 new wells and related facilities. Recommended Best Management Practices to minimize impacts to sensitive species and other wildlife are identified in the Formal Consultation on the Oil and Gas Programmatic in Kings and Kern Counties, California (USFWS 1996). For more information about proposed Best Management Practices and take avoidance measures to help minimize habitat and species impacts, see Biological Resources Condition of Certification BIO-5.

TOXIC GAS EMISSIONS AND POTENTIAL EFFECTS ON SENSITIVE WILDLIFE SPECIES

STUDIES OF THE EFFECTS OF EMISSIONS ON WILDLIFE

Toxic air emissions, in particular hydrogen sulfide gas (H2S), can occur in areas such as the Midway-Sunset oil field as a normal by-product of oil extraction activities. Other oil extraction-related toxic emissions include carbon monoxide and hydrocarbons which, if not controlled, could be emitted at levels that may be toxic to humans and wildlife.

H2S is a colorless gas with a characteristic odor of rotten eggs that is one of the principal compounds involved in the natural cycle of sulfur in the environment (WHO 1981). It occurs in volcanic gases and is produced by bacterial action during the decay of both plant and animal protein. In addition to oil fields, H2S can be found in geothermally active areas. H2S is slightly heavier than air, so it is known to settle into low-lying areas.

H2S in relatively high concentrations can cause dizziness, breathing difficulties, and nausea and is known to be toxic to humans, so many governments have adopted worker occupational exposure limits of 7 – 10 ppm to protect against effects (WHO 1981). In experiments with laboratory animals, the most readily established effects of H2S is the inhibition of the enzyme cytochrome c oxidase involved in tissue oxidative respiration. Such inhibition interferes with tissue use of oxygen such that metabolic demands can not be met.

H_2S STUDIES BY OTHERS

The World Health Organization (WHO 1981) reported results of several studies completed on a number of animals including canary, rat, guinea pig, cat, dog, and goat. In these studies, laboratory animals inhaling H2S at various concentrations displayed symptoms as listed in the following table:

Concentrations	H2S Exposure Duration			
	¼-hour	**½-hour**	**1-hour**	**Many hours**
100 – 150 ppm				Eye & throat irritation
200 – 300 ppm			Eye & mucous membrane irritation	Slight general effects
500 – 700 ppm			Local irritation & slight systemic signs	Death
900 ppm		Serious systemic effects	Death	
1500 ppm	Respiratory collapse	Death		
1800 ppm	Immediate respiratory collapse & death			

The California Environmental Protection Agency's (CalEPA's) Office of Environmental Health Hazard Assessment has produced a draft technical document (CalEPA 1999) establishing noncancer chronic reference exposure levels for H2S. This draft document contains a chronic toxicity summary of the effects on animals exposed to H2S at various levels. In studies completed by the Chemical Industry Institute of Toxicology (CIIT 1983 a, b, c) for example, rats and mice were exposed to 0, 10.1, 30.5, or 80 ppm H2S for 6 hours per day, 5 days per week for 90 days. Measurements of the rat's neurological and hematological functions did not reveal any abnormalities, and a histological examination of the nasal passageway also revealed no significant exposure-related changes. There was however, a significant decrease in body weight of rats exposed to 80 ppm. For mice exposed to 80 ppm, the only exposure-related histological lesion was an inflammation of the nasal membrane. As with the rats, the mice also experienced significant weight loss, although neurological and hematological tests revealed no physiological abnormalities.

The California EPA draft document explains that the adverse effects reported in animal studies of chronic exposure occur at much higher concentrations than effects seen in studies of human acute exposures (page A – 113). In human studies, irritation was reported at concentrations of 2.5 – 5 ppm for 15 minutes (Bhambhani and Singh 1985); however, no effects on laboratory animals were observed at concentrations of up to 80 ppm for 90 days.

STUDIES BY THE ENERGY COMMISSION

A concern over H2S emissions, and their potential effects on local sensitive wildlife species of the Midway-Sunset oil field, prompted the California Energy Commission to fund two preliminary studies to try to ascertain whether or not oil field pollutants were having an effect on the San Joaquin kit fox and other sensitive wildlife.

Spiegel and Dao (1997) measured levels of H2S in kit fox dens, rodent burrows, and ambient air at oil-developed and control sites for six days in southwestern Kern

County. The purpose of the study was to measure H2S levels in the Midway-Sunset oil field and compare these concentrations with concentrations measured at an undeveloped site, the Lokern Natural Area, located approximately 7.7 miles away. Study samples were gathered using an H2S gas meter at each kit fox den site from ambient air, 30 cm in from the den entrance, and 60 cm in from the den entrance. For rodent burrows, study samples were gathered from ambient air and from 15 cm in from the burrow entrance.

Spiegel and Dao's mean level of H2S concentration (ppm) results were as follows:

	Lokern Natural Area (mean)	**Midway-Sunset Oil Field (mean)**
AMBIENT AIR	0.23 ppm	0.31 ppm
KIT FOX DENS		
Ambient	0.25 ppm	0.33 ppm
30-cm depth	0.30 ppm	0.39 ppm
60-cm depth	0.32 ppm	0.43 ppm
RODENT BURROWS		
Ambient	0.20 ppm	0.30 ppm
15-cm depth	0.43 ppm	0.52 ppm

Even though their mean results were found at times to be 10 times higher than the regional ambient standard (0.03 ppm) established in California for human exposure, the authors concluded that H2S levels in ambient air, kit fox dens, and rodent burrows at both study sites were well below concentrations known to cause health effects in experimental animals. Spiegel (personal communication 1999) explained that the H2S meters used may not have been sensitive enough to accurately read levels below 1 ppm, which would explain why Spiegel and Dao's data are higher than those concentrations gathered by the California Union for Reliable Energy (CURE) discussed below.

Given the limitations of the measurement methods used, the reported concentrations by Spiegel and Dao should not necessarily be regarded as accurate measurements. These study results should be seen only as useful for comparing the relative H2S concentrations of the Midway-Sunset oil field with an undeveloped site. The only appropriate conclusion is that H2S levels are, as expected, higher in the oil field than in the undeveloped site 7.7 miles away, but lower than levels (100 – 150 ppm) known to cause effects to laboratory animals.

In an unpublished report [1] funded by the Energy Commission (Charlton 1997), clinical studies were completed to determine whether differences in deer mice (*Peromyscus maniculatus*) histology, kit fox hematologic and serum chemistry values, deer mice hepatic mono-oxygenase activity, and kit fox tissue trace metal concentrations could be detected between animals inhabiting the Midway-Sunset oil

[1] Dr. Charlton's paper was rejected for publication by the Journal of Wildlife Diseases. Three reviewers indicated that the paper contained some potentially interesting preliminary results, but that the study was incomplete, lacked a large enough sample size, and did not contain enough data to support the author's conclusions.

field and the Lokern Natural Area. According to Dr. Charlton (personal communication 1999), the hematology data she collected from the foxes and the histopathology she completed on deer mice tissue samples showed some differences between the two populations, but did not indicate with any certainty what the cause of the blood and tissue sample differences are due to. Moreover, she found no data to conclude that exposure to H2S was the cause for the differences in the blood and tissue samples. So Dr. Charlton has urged staff not to rely upon her unpublished study to provide any definitive answer regarding whether or not local wildlife is being impacted by exposure to H2S.

After Dr. Charlton her toxicological studies she concluded that more work needed to be done before any definitive conclusions can be drawn. She recommends a study that exposes “clean” laboratory animals to the environment to rule out factors such as genetics, nutrition, age, and reproductive status, all of which could have affected her results. She stated that such a study would only demonstrate whether there are hematological and histological differences as a result of the environmental exposure. She pointed out that even if effects could be definitively demonstrated, it would be nearly impossible to attribute them specifically to H2S exposure, given the extremely complex mixture of chemicals present in the oil field environment (Charlton, personal communication, 1999.). For these reasons, staff has not relied upon the Charlton study for conclusions on the possible wildlife impacts of oil field related H2S emissions in Kern County.

The Energy Commission also funded studies (CEC 1996) that did not specifically address the H2S issue, but instead focused on comparing San Joaquin kit fox survivorship and reproductive success in the undeveloped Lokern Natural Area and oil-developed areas of the Midway-Sunset oil field. This study found that oil field activities did not appear to affect kit fox survivorship or reproduction. The study documented fewer kit foxes in the oil-developed areas; however, when the oil field foxes were compared to non-oil field developed area foxes the author found that there appeared to be no significant difference in how long the oil-field developed foxes lived and how many pups they had. These findings were made in spite of the fact that there is, among other things, the potential for exposure to high concentrations of H2S and other potentially toxic air emissions in the Midway-Sunset oil field.

AMBIENT H2S LEVELS AND PROJECTED INCREASES IN H2S LEVELS

There are no regional air quality monitoring stations located in the Midway-Sunset oil field area, so no regional ambient H2S data have been gathered (Loyer personal communication 1999). The California Air Resources Board has established a regional ambient air quality standard for humans of 0.03 parts per million (ppm) for California for H2S, but lists the Kern County oil field area as Unclassified [2] with regards to this standard. This concentration reflected in the standard is significantly lower than the high concentrations normally found to cause effects in laboratory animal studies.

[2] This classification means that there is not enough information to determine if the area is in violation of current ambient air quality standards.

CURE gathered H2S field data (CURE 1999g, Exhibit 5) in the Midway-Sunset oil field and the Lokern Natural Area on August 28th, August 30th, and September 1st, 1999. A summary of CURE's mean H2S readings is as follows:

Date	Lokern Natural Area (mean)	Midway-Sunset oil field (mean)
8/28/99	0.0058 ppm	0.0103 ppm
8/31, 9/1/99	0.0032 ppm	0.0235 ppm

CURE stated (CURE 1999g, Exhibit 5) that these mean concentrations exceed the ambient air quality standard (0.03 ppm) established by the California Air Resources Board, however they clearly do not. Approximately 26% of CURE's individual field readings were above the ambient standard, but the mean concentrations were not. Staff can not confirm the accuracy or representativeness of CURE's measurements, and does not believe that they constitute sufficient evidence to conclude that ambient conditions are above the state standard.

Moreover, there are significant uncertainties involved in trying to estimate the effect of the project on these levels. H2S emissions will vary greatly from well to well and will not be known until the wells are actually constructed and tested. This makes any estimate of emissions very difficult, and hence any estimate of the effects of the project highly speculative [3]. In light of these uncertainties and the lack of data demonstrating an unequivocal link between even the highest measurements (which are unreliable) and potential adverse effects on local wildlife species, staff believes that there is no persuasive evidence that H2S emissions from this project will create a significant adverse impact to sensitive wildlife. Staff also believes that no additional analysis can be completed within the near term that would provide additional useful information about this issue.

On December 8, 1999, staff consulted other agency biologists who are assigned to analyze this project on the H2S issue. These biologists, representing the California Department of Fish and Game, the U. S. Fish and Wildlife Service, and the Bureau of Land Management, concluded that they support staff's conclusions. In addition, they indicated that they did not anticipate a need for this project to provide any additional mitigation to address potential H2S wildlife impacts (Saslaw et al 1999).

For a discussion of the H2S issue regarding the potential for human health effects, see the **Public Health** and **Air Quality** sections.

POTENTIAL IMPACTS TO BIRDS AT VALLEY WASTE

The project will use produced water from the Midway-Sunset oil field to create steam in the heat recovery steam generator. The produced water used by the project will be treated in a water treatment system operated by Texaco before it reaches the Sunrise facility, and the water treatment residuals including regeneration brine, are proposed to be disposed of at a facility identified as Valley Waste located in the vicinity of the Midway-Sunset oil field.

[3] Staff notes that volatile organic compound emissions, which include the H2S emissions, of the 700 new oil production and steam injection wells will be controlled by vapor control devices to a 99.9% efficiency level.

The regeneration brine and other waste from the project may contain benzene and mercury (CURE 1999l) that may effect local wildlife if exposed to the waste. At Valley Waste, the regeneration brine and other waste streams are placed into the first of a series of sediment ponds. The first few ponds are screened to prevent birds and other wildlife access to water that could be hazardous. However, the last few ponds are unscreened, and access, primarily by birds, is relatively unrestricted.

SCPC has not provided an analysis of the produced water, so staff lacks enough information to decide whether or not the resulting waste stream is likely to be toxic to birds in the Valley Waste unscreened ponds. Staff is coordinating with the Department of Toxic Substance Control to evaluate the environmental effects of use of the produced water, and will jointly issue data requests today (12/17/1999) on this issue.

Once this information is provided, staff will ascertain whether or not this potential impact is significant and whether additional mitigation is required. In the event that staff ultimately concludes that potentially significant wildlife impacts may occur if birds are exposed to hazardous levels of benzene, mercury and other trace elements found in the unscreened ponds at Valley Waste (and that this project will be contributing to those hazardous elements), staff will recommend that the Commission impose a condition of certification to address this potential impact.

CUMULATIVE IMPACTS

The California Environmental Quality Act defines cumulative impacts as “two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts.” Cumulative impacts can occur when individually minor but collectively significant projects taking place over time.

The Sunrise project will, if built, be located in an area of western Kern County that has experienced extensive energy development, and this development will continue. There is the potential for at least three additional power plants (La Paloma, Midway-Sunset, and Elk Hills), in addition to the Sunrise project, to be built in the region in the near future. In addition, the proposed project will provide steam to approximately 1300 existing wells for enhanced oil recovery. Current oil field development in the region includes the installation of a new aboveground utility corridor to be utilized for water, natural gas, and steam distribution. Also, the entire Kern River Gas Transmission Company/Mojave Pipeline Company interconnecting 20-inch natural gas pipeline is currently being installed to link up with the TCI Main Utility Corridor and provide natural gas to the proposed SCPP power plant. Finally, there is the overall anticipated expansion of the Midway-Sunset oil field that is expected over the next few years.

All of this energy-related, oil field development in the Midway-Sunset oil field has the potential to impact sensitive species and their habitats. As an example, vehicles may hit individual sensitive species. In addition, permanent habitat losses will occur as projects are constructed. Some of this energy development requires only Kern County approval, while other types require state agencies approval from agencies such as the Energy Commission and the Division of Oil and Gas and Geothermal Resources.

Because there are so many sensitive species in the region, federal agencies such as USFWS and BLM are also involved in developing regional strategies to minimize impacts to sensitive species and their habitat. BLM and USFWS have implemented an oil and gas programmatic (a "biological opinion") for Kings and Kern Counties (USFWS 1996) that addresses, for BLM leaseholds, the protection of sensitive species and their habitat. SCPC will be required to abide by the oil and gas programmatic established by the USFWS and BLM to address sensitive species issues related to oil field development. In addition, SCPC will be required to abide by the conditions of certification established by Energy Commission staff to avoid impacts whenever possible, and to minimize impacts when impacts are unavoidable.

Habitat loss in western Kern County is an ongoing regional concern of CDFG, BLM, USFWS, and the Energy Commission. To address this issue for western Kern County, CDFG and the USFWS look for habitat compensation when habitat losses are anticipated for all development projects, including energy projects.

For the SCPP, the applicant has indicated (SCPP 1999n) that they intend to provide suitable habitat compensation funds to The Center for Natural Lands Management so suitable compensation habitat can be purchased and added to the current Lokern Preserve in the Lokern Natural Area. SCPC has also indicated that they intend to implement take avoidance measures to minimize impacts to individual species. Habitat compensation will involve the purchase of an agreed-to amount of compensation habitat and the establishment of a suitable endowment to guarantee perpetual protection of the compensation habitat. Implementation of take avoidance measures will help minimize impacts to individual species. By doing so, SCPC will not only be addressing its direct and indirect habitat compensation responsibilities and instituting take avoidance measures, but also eliminating staff's concern that the project will contribute to any cumulative species or habitat losses. The SCPC habitat compensation will occur within the geographic area that is to be impacted, and the compensation will be provided to an existing regional preserve to address the regional habitat loss problem associated with the region's continuing energy development. In addition, far more habitat will be protected than is being impacted, and the protected habitat will be of much higher quality and value for the region's sensitive species than that which is being impacted.

SCPP will be creating some H2S emissions during construction and operation of the anticipated 700 new oil production and steam injection wells, and the SCPP contribution will be added to what is already present in the region as a result of other oil field development activities. In high enough concentrations (80+ ppm) this toxic gas has been shown to impact laboratory animals. However, the late August and early September 1999 ambient mean concentrations of 0.0103 ppm and 0.0235 ppm recorded by the California Union for Reliable Energy (CURE 1999) are well below concentrations where laboratory animals experience eye and throat irritation. For this reason, staff does not believe that the SCPP H2S contribution to the current mean ambient H2S concentration will create a situation where additional mitigation is necessary to address cumulative impacts.

For all of these reasons, staff does not believe that the project will create any incremental effects that are cumulatively considerable; and the combined impact associated with Sunrise's incremental effect and the effects of other related projects is therefore not considered to be significant.

FACILITY CLOSURE

Sometime in the future, the SCPP will experience either a planned closure, or be unexpectedly (either temporarily or permanently) closed. When facility closure occurs, it must be done in such a way as to protect the environment and public health and safety. To address facility closure, an "on-site contingency plan" will be developed by the project owner, and approved by the Energy Commission Compliance Project Manager (See **General Conditions** section in **Facility Closure** and Biological Resources Condition of Certification **BIO-11**). Facility Closure mitigation measures will also be included in the Biological Resources Mitigation Implementation and Monitoring Plan (See Biological Resources Condition of Certification **BIO-9**).

PLANNED OR UNEXPECTED PERMANENT FACILITY CLOSURE

The region surrounding the proposed project site is a mosaic of disturbed and undisturbed valley saltbush scrub and non-native annual grassland habitats. The undisturbed and disturbed habitats are dominated by native and non-native plant species that provide food and cover for the associated species, including several protected plant and wildlife species. Since the proposed project area currently provides habitat for these species, the facility closure plan needs to address habitat restoration measures to be implemented in the event of a planned or an unexpected permanent closure. Habitat restoration measures that should be addressed include such tasks as the removal of all power plant site structures and the immediate implementation of habitat restoration measures to re-establish native plant species and native habitat types (e.g., valley saltbush scrub). In addition, planned or unexpected permanent facility closure may also trigger the removal of the transmission conductors, and possibly the entire transmission line, since birds are known to collide with transmission conductors.

UNEXPECTED TEMPORARY CLOSURE

Staff does not have any biological resource facility closure recommendations in the event of an unexpected temporary closure of the Sunrise power plant. However, in the event that the Energy Commission CPM decides that the facility is permanently closed, the above-mentioned facility closure measures need to be given careful consideration.

MITIGATION

SPCP has developed a mitigation strategy that maximizes the avoidance of impacts to sensitive species and their habitat (SCPP 1998a). Where avoidance is not possible, SPCP has proposed to implement a habitat compensation strategy for both temporary and permanent, direct and indirect impacts associated with the project. In the AFC, SPCP has provided mitigation strategies for project design and siting, pre-construction, construction, post-construction, operation and maintenance activities. The applicant's proposed mitigation measures include avoidance of sensitive areas, designing/building transmission line towers to minimize bird electrocutions and collisions, implementing a worker environmental awareness program, designating a biologist to oversee the implementation of all biological resource mitigation measures, implementation of sensitive species take avoidance measures, minimization of habitat disturbance activities, monitoring all activities that could result in a take of a sensitive species, implementation of a habitat reclamation plan once temporary habitat disturbance is completed, prohibiting firearms and pets from the work site, acquisition of compensation habitat, and establishment of an endowment. For a complete list of mitigation measures proposed by SCPC, see Biological Resources Condition of Certification **BIO-1**.

To make certain that all proposed mitigation measures are properly implemented during project construction and operation, SCPC will educate its workers about the sensitive biological resources in the project region (Worker Environmental Awareness Program) and create a Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP). A first draft of the BRMIMP (SCPP 1999n) was provided on June 15, 1999, and has been reviewed by staff. The BRMIMP, when finalized prior to the start of any project-related habitat disturbance activities, will identify:

- Specific take avoidance measures to protect sensitive species during project construction;
- Worker Environmental Awareness Program material;
- Specific measures to avoid sensitive species during project operation (e.g., speed limits, prohibition of firearms at the project site, and trash controls);
- Habitat rehabilitation measures for temporarily disturbed areas; and
- Habitat compensation and endowment amount for direct and indirect impacts.

For information about the Worker Environmental Awareness Program and the BRMIMP, see Biological Resources Conditions of Certification **BIO-6** and **BIO-9**.

SCPC will also work with staff to develop a landscape plan that will provide a suitable visual screen for the project site that utilizes trees and/or shrubs that are suitable for wildlife species of western Kern County. See the **Visual Resources** and the **Land Use** sections for more information.

BLUNT-NOSED LEOPARD LIZARD

The blunt-nosed leopard lizard is a Fully Protected species (Fish and Game Code section 5050), and the Fish and Game Code prohibits take of any species with this classification. As a result, SCPC must employ all feasible means to avoid take during project construction and operation. Avoidance measures (e.g. use of fiber optics to locate active burrows and barrier fencing to keep leopard lizards out of work areas) will be developed in consultation with the CDFG and USFWS, and included in the SCPP Biological Resources Mitigation Implementation and Monitoring Plan. See Biological Resources Condition of Certification **BIO-9** for more information about the mitigation implementation and monitoring plan.

BURROWING OWL

The burrowing owl is protected by the Migratory Bird Treaty Act (Fish and Game Code 3513) since it does migrate each year from areas that have cold winter temperatures. Burrowing owls found in the project area of western Kern County and other areas of California's Central Valley do not migrate, but are residents since winter temperatures are more favorable. To avoid impacting the burrowing owl, SCPC must implement avoidance measures during project construction and operation. Examples of recommended avoidance measures include avoiding nesting burrows during nesting season, constructing artificial burrows when appropriate, and using passive relocation methods instead of trapping. Implementation measures for final burrowing owl avoidance protocols will be developed in consultation with CDFG and USFWS, and be included in the SCPP Biological Resources Mitigation Implementation and Monitoring Plan. See Biological Resources Condition of Certification **BIO-9**.

SCPC HABITAT COMPENSATION

The sensitive species list is long for western Kern County because a significant portion of the natural habitat has been lost to various types of development, including energy development and agriculture. To adequately address habitat loss associated with the SCPP, SCPC has proposed, and staff will require, that mitigation funds be provided for habitat compensation. Staff feels that habitat conservation through habitat compensation can help promote the recovery of several of the state and federally listed species that occur in western Kern County.

Habitat compensation ratios to calculate the amount of compensation acreage to be purchased to compensate for the amount of acreage to be disturbed were provided by the USFWS and CDFG during pre-filing discussions held between agency personnel, staff and the SCPC. The following habitat compensation ratios (numbers of acres to be purchased per each acre to be impacted) will be utilized by SCPC:

TYPE OF HABITAT IMPACT	COMPENSATION RATIO
Permanent impacts to "conserved" land	4.0:1
Permanent impacts to other private land	3.0:1
Temporary impacts to conserved land	2.1:1
Temporary impacts to other private land	1.1:1

"Conserved" lands are defined as lands owned by the state or federal government or lands that are privately owned that are currently managed to benefit local wildlife. For the SCPP, the Route B transmission line corridor will cross "conserved" lands. Public lands managed by BLM, private lands owned and managed by The Center for Natural Lands Management as part of its Lokern Preserve, and state-owned land managed by the California Department of Fish and Game at the Lokern Ecological Reserve are all found within the Route B corridor.

As of June 15,1999, SCPC has identified that the SCPP direct impacts will result in the following acreage impacts and require the following compensation:

	Impact Acreages	Comp. Ratio	Comp. Acreages
Permanent impacts to "conserved" habitat	= 1.3 acres	x 4.0 =	5.2 acres
Permanent impacts to other private habitat	= 27.5 acres	x 3.0 =	82.5 acres
Temporary impacts to conserved habitat	= 3.5 acres	x 2.1 =	7.4 acres
Temporary impacts to other private habitat	= 28.0 acres	x 1.1 =	30.8 acres
TOTAL COMPENSATION ACREAGE FOR DIRECT IMPACTS			**125.9 acres**

In addition, the Sunrise project's indirect impacts will result in the following acreage loss and require the following compensation:

	Impact Acreage	Comp. Ratio	Comp. Acreage
Permanent impacts other private habitat	= 176.4 acres	x 3.0 =	529.2 acres
TOTAL COMPENSATION ACREAGE FOR INDIRECT IMPACTS			**529.2 acres**

The total of the direct and indirect compensation acreages, 655.1 acres (125.9 acres + 529.2 acres), SCPC will be required to provide adequate funds to cover all the costs associated with the purchase of at least **655.1 acres** of suitable habitat.

Staff recommends that the required compensation funds be provided by the project owner to CNLM, and that the funds be used to purchase at least 655.1 acres of compensation habitat in the immediate vicinity of the CNLM Lokern Preserve within the Lokern Natural Area of western Kern County. The CNLM Lokern Preserve, located within the Lokern Natural Area, is located approximately 10 miles north of the proposed Sunrise power plant site. The CNLM preserve contains the same types of habitat and sensitive species that will be impacted during Sunrise project construction. The Lokern Preserve was originally established by The Nature Conservancy in the late 1980's, however it is now owned and managed by CNLM, a private, non-profit organization dedicated to the protection and management of natural resources.

It is staff's opinion that the location of the proposed habitat compensation will, when completed, provide a significant overall net benefit to the local species and habitat protection efforts because at least 655 acres of high quality habitat will be purchased and protected as part of the Lokern Preserve to compensate for the direct permanent loss of 28.8 acres, temporary disturbance to 31.5 acres, and the indirect permanent loss of 176.4 acres. The vast majority of this project's habitat impacts will not be to high quality habitat found in the vicinity of the Lokern Preserve, but instead to habitat found in a heavily developed oil field.

To calculate the dollar amount needed for habitat compensation if CNLM assumes responsibility for the habitat purchases, staff consulted Brenda Pace (CEC 1999tt), Administrative Director for CNLM. Ms. Pace indicated that the required amount must be large enough to cover all acreage purchases, as well as all administrative costs including initial and capital costs, and the establishment of a suitable endowment for perpetual care of the habitat.

The per acre costs identified by CNLM are:

- Average price = $500;
- All administrative costs including initial and capital expenses = $170; and
- Endowment = $330

Total dollar amount required by CNLM = $1000 per acre

Habitat compensation will be required for 655.1 acres, and CNLM requires $1000 per acre to assume the responsibility of purchasing the compensation habitat to add the required compensation acreage to its Lokern Preserve. As a result, staff will require SCPC to provide $655,100 to CNLM prior to the start of any project-related ground disturbance activity.

Additional habitat compensation funds may be required if more habitat is disturbed than is anticipated. For additional information about the Sunrise project habitat compensation, refer to Biological Resources Condition of Certification **BIO-10**.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

To be in compliance with applicable laws, ordinances, regulations and standards, SCPC must obtain, and build and operate the SCPP within the terms and conditions provided in a state Incidental Take Permit and a federal Biological Opinion. As a result of the need for SCPC to obtain a right-of-way permit from BLM for a portion of the transmission line route, BLM will be required to initiate a Section 7 consultation with the USFWS, which will result in the USFWS issuing a federal Biological Opinion. In addition, SCPC, per section 2081.1 of the Fish and Game Code, must also acquire an Incidental Take Permit. These documents will provide mitigation measures required by each regulatory agency. For further information on these documents, see Biological Resources Conditions of Certification **BIO-7** and **BIO-8**.

To help the project owner comply with laws, ordinances, regulations, and standards and the biological resource mitigation measures associated with this project, SCPC must designate a biological resource specialist (“Designated Biologist”), prior to the beginning of any project-related ground disturbance, who is familiar with the biological resource issues of the Sunrise project. The Designated Biologist will help the project owner ensure that all biological resources mitigation measures are complied with during project construction and operation. For more information about the roles and responsibilities of the Designated Biologist, see Biological Resource Conditions of Certification **BIO-2, BIO-3, BIO-4** and **BIO-5**.

UNRESOLVED ISSUES, CONCLUSIONS, AND RECOMMENDATIONS

UNRESOLVED ISSUES

FEDERAL BIOLOGICAL OPINION & STATE INCIDENTAL TAKE PERMIT

SCPC has not yet received a federal Biological Opinion from the USFWS and an Incidental Take Permit from CDFG. As a result, final mitigation requirements from these agencies are unknown at this time. However, mitigation measures recommended by SCPC in their application and in their draft Biological Resources Mitigation Implementation and Monitoring Plan (SCPP 1999n) have not been rejected by representatives of either agency. As a result, staff expects that when the federal and state documents are provided, the required mitigation will be consistent with what SCPC and staff have proposed, and SCPC will implement all required mitigation. Staff has been informed by the USFWS that the federal Biological Opinion will be available no sooner than early January 2000 (Jones personal communication 1999). The state Incidental Take Permit will not be provided until after the Energy Commission final decision document is released.

PROJECT'S WASTE STREAM AND POTENTIAL BIRD IMPACTS AT VALLEY WASTE

The issue of whether or not the project's waste stream, to be disposed of at Valley Waste, will be contributing to potential impacts to birds utilizing unscreened sediment ponds at the waste disposal facility is currently unresolved.

CONCLUSIONS

Since staff does not have sufficient information to ascertain whether or not birds will be adversely affected at the Valley Waste facility, staff can not recommend approval of this project at this time.

RECOMMENDATIONS

To help make certain that the SCPP is in compliance with all laws, ordinances, regulations and standards during project construction and operation, staff recommends that the Energy Commission adopt the following Biological Resources Conditions of Certification.

CONDITIONS OF CERTIFICATION

The following Biological Resources Conditions of Certification are proposed by staff.

SCPC MITIGATION

BIO-1 The project owner will implement the mitigation measures identified in Section 8.2, pages 8.2-20 to 8.2-22 of the SCPC Application for Certification (SCPP 1998a). The project owner's proposed mitigation measures will be incorporated into the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) (see Condition of Certification BIO-9, below) unless the mitigation measures conflict with mitigation required by the U. S. Fish and Wildlife Service and the California Department of Fish and Game contained in the federal Biological Opinion and state Incidental Take Permit, respectively. If there is a conflict between the draft BRMIMP and the federal Biological Opinion and/or the state Incidental Take Permit, then the federal and/or state conditions or mitigation measures will supercede those found in the BRMIMP.

Protocol:

8. Prior to the onset of ground-disturbance activities, project personnel shall be briefed on the occurrence and distribution of listed species in the project area, measures that are being implemented to protect these species during project actions, and the reporting requirements should incidental take occur. New workers will receive training within 15 days of their first day of employment.
9. No more than 14 days prior to commencement of construction activities, a qualified biologist(s) shall conduct pre-activity surveys of proposed work zones (for the power plant, natural gas pipelines, water pipeline, and transmission line) and the 500-foot buffer around each area. During pre-activity surveys, the status of previous surveys shall be reviewed. San Joaquin kit fox dens and kangaroo rat and blunt-nosed leopard lizard burrows shall be flagged for avoidance, as necessary, and additional habitat features, if any, shall be identified and flagged as necessary.
10. Biological monitors (an SCPC term) shall:

- Accompany initial grading crews throughout the project area at all times that activities with the potential to affect listed species are being conducted;
- Conduct pre-activity surveys as described above;
- Aid project crews in satisfying avoidance criteria and implementing project mitigation as described in this assessment;
- Aid in relocating access roads and laydown areas as necessary;
- Inspect open trenches and footing holes for stranded wildlife and remove as necessary each morning;
- Observe and note all pertinent information concerning project effects on listed species; and,
- Assist project personnel in conducting the proposed project in such a manner as to minimize adverse impacts on listed species.

11. Pets shall not be permitted on the project site during construction activities.
12. All food-related trash shall be disposed of in closed containers only and regularly removed from the project site.
13. All spills of hazardous materials within listed species habitat shall be cleaned up immediately.
14. No firearms will be allowed in the project area.
15. All construction activities conducted during the project shall be confined to daylight hours, unless within a site perimeter fence or unless circumstances warrant night work and approval is obtained from CDFG and USFWS.
16. All project-related vehicles shall observe a speed limit of 20 miles per hour or less on all routes that traverse listed species habitat, except on state and county highways and roads.
17. Project-related vehicles shall be confined to existing primary or secondary roads or to specifically delineated project areas (i.e., areas that have been surveyed and described in existing documentation). Otherwise, no off-road vehicle travel shall be permitted.
18. All open trenches and footing holes shall be covered each night or ramped in such a way as to allow wildlife that may enter to escape unharmed. Ramps will be no more than 1,000 feet apart and no more than 45 degrees.
19. All known and potential San Joaquin kit fox dens, giant kangaroo rat burrows, San Joaquin antelope squirrel burrows, and burrows potentially inhabited by blunt-nosed leopard lizards shall be protected by implementing the following procedures. Such protection will help prevent incidental take of dens and burrows in excess of the take limits allowed by the resource agencies.
20. All avoidable San Joaquin kit fox dens, giant kangaroo rat, San Joaquin antelope squirrel and blunt-nosed leopard lizard burrows within the immediate vicinity of work areas shall be prominently staked and/or flagged as necessary to alert project personnel to their presence. All project-related flagging shall be collected and removed after completion of the project construction.
21. The project owner shall make every reasonable effort to prevent the collapse of dens and burrows by relocating temporary access roads and laydown areas to avoid dens and burrows or other means as determined to be appropriate for the sensitive wildlife and botanical resources.
22. Avoidance criteria for sensitive wildlife and botanical resources:

- 200 feet from San Joaquin kit fox pupping dens;
- 100 feet from known San Joaquin kit fox dens;
- 50 feet from potential San Joaquin kit fox dens;
- 50 feet from giant kangaroo rat burrow systems;

- 50 feet from burrows where San Joaquin antelope squirrels or blunt-nosed leopard lizards were sighted;
- 50 feet from potential blunt-nosed leopard lizard burrows; all small mammal burrows of sufficient size will be considered potential blunt-nosed leopard lizard burrows in areas where potential habitat for this species exists; and
- 30 feet from any sensitive annual plant population that is in the state of reproduction (germination-seed set).

23. Within 45 calendar days after completion of construction, the project proponent shall submit a post-activity compliance report that details the following information: dates that construction occurred; pertinent data concerning success in meeting project mitigation measures, if any; known project effects on San Joaquin kit fox, blunt-nosed leopard lizards, and giant kangaroo rats or other sensitive species, if any (including specific number of dens and small mammal burrows damaged or destroyed); occurrences of incidental take of federally listed species, if any; an assessment of the extent and severity of project impacts on all sensitive wildlife habitat; and other pertinent information.
24. The top 4 inches of topsoil shall be stockpiled near all lands that will be temporarily disturbed by grading during construction activities. These sites shall be recontoured and preserved topsoil shall be spread to aid in the reclamation of these sites after construction is complete.
25. The project owner will acquire agency-approved lands containing habitat similar to the habitat being disturbed during construction and operation of the proposed facilities (that will be preserved and managed for sensitive wildlife and plant species into perpetuity) or purchase credits in an established preserve in the following amounts:

- 3.0 acres for each acre of habitat permanently disturbed (private lands);
- 1.1 acres for each acre of habitat temporarily disturbed (private lands);
- 4.0 acres for each acre of habitat permanently disturbed (conserved lands and BLM)
- 2.1 acres for each acre of habitat temporarily disturbed (conserved lands and BLM)

Verification: At least 60 days prior to start of any project related ground disturbance activities, the project owner shall provide the Energy Commission Compliance Project Manager (CPM) with the Biological Resources Mitigation Implementation and Monitoring Plan for the SCPP, and the CPM will determine the plans acceptability within 15 days of receipt of the plan. Implementation of the above measures will be included in the BRMIMP.

DESIGNATED BIOLOGIST

BIO-2 Construction site and/or ancillary facilities preparation (described as any ground disturbing activity other than Energy Commission approved geotechnical work) shall not begin until an Energy Commission CPM approved Designated Biologist is available to be on site.

Protocol: The Designated Biologist must meet the following minimum qualifications:

1. A Bachelor's Degree in biological sciences, zoology, botany, ecology, or a closely related field;
2. Three years of experience in field biology or current certification of a nationally recognized biological society, such as The Ecological Society of America or The Wildlife Society;
3. One year of field experience with biological resources found in or near the project area; and
4. An ability to demonstrate to the satisfaction of the CPM the appropriate education and experience for the biological resources tasks that must be addressed during project construction and operation.

If the CPM determines the proposed Designated Biologist to be unacceptable, the project owner shall submit another individual's name and qualifications for consideration. If the approved Designated Biologist needs to be replaced, the project owner shall obtain approval of a new Designated Biologist by submitting to the CPM the name, qualifications, address, and telephone number of the proposed replacement. No disturbance will be allowed in any designated sensitive areas until the CPM approves a new Designated Biologist and the new biologist is on site.

Verification: Verification: At least 90 days prior to the start of any ground disturbance activities, the project owner shall submit to the CPM for approval, the name, qualifications, address and telephone number of the individual selected by the project owner as the Designated Biologist. If a Designated Biologist is replaced, the information on the proposed replacement, as specified in the condition, must be submitted in writing at least ten working days prior to the termination or release of the preceding Designated Biologist.

BIO-3 The CPM approved Designated Biologist shall perform the following during project construction and operation:

5. Advise the project owner's Construction Manager on the implementation of the Biological Resource Conditions of Certification;
6. Supervise or conduct mitigation, monitoring and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources, such as, wetlands and special status species; and

7. Notify the project owner and the CPM of any non-compliance with any Biological Resources Condition of Certification.

<u>Verification:</u> During project construction, the Designated Biologist shall maintain written records of the tasks described above, and summaries of these records shall be submitted along with the Monthly Compliance Reports to the CPM. During project operation, the Designated Biologist shall submit record summaries in the Annual Compliance Report.

BIO-4 The project owner's Construction Manager shall act on the advice of the Designated Biologist to ensure conformance with the Biological Resources Conditions of Certification.

<u>Protocol:</u> The project owner's Construction Manager shall halt, if necessary, all construction activities in areas specifically identified by the Designated Biologist as sensitive to assure that potential significant biological resource impacts are avoided.

The Designated Biologist shall:

8. Inform the project owner and the Construction Manager when to resume construction, and
9. Advise the CPM if any corrective actions are needed or have been instituted.

<u>Verification:</u> Within two (2) working days of a Designated Biologist notification of non-compliance with a Biological Resources condition of certification or a halt of construction, the project owner shall notify the CPM by telephone of the circumstances and actions being taken to resolve the problem or the non-compliance with a condition. For any necessary corrective action taken by the project owner, a determination of success or failure will be made by the CPM within five (5) working days after receipt of notice that corrective action is completed, or the project owner will be notified by the CPM that coordination with other agencies will require additional time before a determination can be made.

BIO-5 To minimize impacts to sensitive species and their habitat during construction of the expected 700 new oil production wells, steam injection wells, and appurtenant facilities within the ¾-mile radius zone of influence of the SCPP, the project owner will establish a Memorandum of Understanding or similar document between Sunrise and the oil field developer, Texaco California International's (TCI), which will contain TCI's commitment to implement the Best Management Practices and take avoidance measures listed in the BLM's San Joaquin Valley Oil and Gas Opinion Heavy Oil Density Requirements (BLM 1996) to minimize impacts to the San Joaquin kit fox, their dens, and their habitat. These Best Management Practices and take avoidance measures will be implemented within the ¾ mile radius oil production area for BLM leaseholds as well as on private leaseholds as identified as well development areas.

Protocol:

10. Habitat surveys will be completed to locate San Joaquin kit fox dens.
11. Surveys will be completed to look for natal, known, and potential dens.
12. 200-foot buffer around the proposed area of construction will also be surveyed.
13. Natural lands and habitat features will be avoided as practicable. Previously disturbed sites will be utilized whenever practicable.
14. Specific San Joaquin kit fox protection measures will be followed.
15. Natural drainage patterns will be maintained to the greatest extent practicable.
16. Large drainages containing saltbush and other native shrubs will be avoided to the greatest extent practicable.
17. The speed limit on unpaved roads not maintained by the county, shall be a maximum of 25 mph, in order to minimize wildlife casualties.
18. All spills of hazardous materials within endangered species habitats shall be cleaned up immediately.
19. Listed species shall be protected from the hazards posed by oil sumps. All exposed oil sumps shall be screened or eliminated. All screening of sumps shall meet the following specifications: 1. Be not greater than 2-inch nominal mesh, 2. Be of sufficient strength to restrain entry of wildlife, and 3. Be supported in such a manner so as to prevent contact with the sump fluid. Oil sumps shall be designed, constructed, and maintained so they are not a hazard to people, livestock, or wildlife, including birds. Oil sumps shall be filled with earth after removal of harmful materials.
20. Law enforcement personnel and biologists from the California Energy Commission, California Department of Fish and Game, and the U. S. Fish and Wildlife Service shall be given complete access to the project area to review monitoring and mitigation activities.
21. Project activities that are likely to cause the amount or extent of take to be exceeded shall cease immediately.
22. The wildlife protection measures being implemented for listed species shall be extended to candidate and proposed species in the project area to the maximum extent practicable.
23. Restoration will be required when a project or lease is abandoned. Restoration will be encouraged for unused portions of the project area or oil and gas lease. The BLM will be contacted for specific restoration requirements upon project completion.

Verification: No later than 30 days prior to start of any project-related ground disturbing activities for the SCPP, SCPC will provide, to the CPM, a copy of the Memorandum of Understanding or similar document that is established between SCPC and TCI that documents TCI's commitment to implement the above-mentioned kit fox take avoidance measures during the development of the 700 new oil production and steam injection wells. The commitment document will include the name and qualifications of the TCI Designated Biologist to implement the Best Management Practices and take avoidance measures. The TCI Designated Biologist qualifications shall be comparable to those identified in Condition of Certification BIO-2. Survey protocols, mitigation measures, and a copy of the TCI commitment document will be included in the SCPC Biological Resources Mitigation Implementation and Monitoring Plan. During the construction phase of 700 wells and associated development, SCPC will include in its annual reports copies of TCI's survey reports and a discussion of the mitigation measures that were implemented pursuant to the Memorandum of Understanding or other commitment document. For a complete list of what must be included in the mitigation and monitoring plan, see Condition of Certification **BIO–9**.

WORKER ENVIRONMENTAL AWARENESS PROGRAM

BIO-6 The project owner shall develop and implement a CPM approved Worker Environmental Awareness Program in which each of its employees, as well as employees of contractors and subcontractors who work on the project site or related facilities during construction and operation, are informed about sensitive biological resources associated with the project.

Protocol: The Worker Environmental Awareness Program must:

24. Be developed by the Designated Biologist and consist of an on-site or training center presentation in which supporting written material is made available to all participants;
25. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas;
26. Present the reasons for protecting these resources;
27. Present the meaning of various temporary and permanent habitat protection measures; and
28. Identify whom to contact if there are further comments and questions about the material discussed in the program.

The specific program can be administered by a competent individual(s) acceptable to the Designated Biologist.

Each participant in the on-site Worker Environmental Awareness Program shall sign a statement declaring that the individual understands and shall abide by the guidelines set forth in the program materials. The person administering the program shall also sign each statement.

Verification: At least 60 days prior to the start of rough grading, the project owner shall provide copies of the Worker Environmental Awareness Program and all supporting written materials prepared by the Designated Biologist and the name and qualifications of the person(s) administering the program to the CPM for approval. The project owner shall state in the Monthly Compliance Report the number of persons who have completed the training in the prior month and a running total of all persons who have completed the training to date. The signed statements for the construction phase shall be kept on file by the project owner and made available for examination by the CPM for a period of at least six (6) months after the start of commercial operation. During project operation, signed statements for active project operational personnel shall be kept on file for the duration of their employment and for six (6) months after their termination.

CALIFORNIA DEPARTMENT OF FISH & GAME INCIDENTAL TAKE PERMIT

BIO-7 Prior to start of any ground disturbance activities, the project owner shall acquire an Incidental Take Permit from CDFG in accordance with Section 2081(b) of the California Fish and Game Code and implement the permit terms and conditions.

Verification: No less than five (5) days prior to the start of any project related ground disturbance activities, the project owner shall submit to the CPM a copy of the final CDFG Incidental Take Permit. Permit terms and conditions will be incorporated into the Biological Resources Mitigation Implementation and Monitoring Plan. See also Condition of Certification BIO-9.

U.S. FISH & WILDLIFE SERVICE SECTION 7 BIOLOGICAL OPINION

BIO-8 Prior to the start of any ground disturbance activities, the project owner shall provide a final copy of the Biological Opinion in accordance with Section 7 of the federal Endangered Species Act obtained from the U. S. Fish and Wildlife Service and incorporate the terms of the opinion into the Biological Resources Mitigation Implementation and Monitoring Plan. The project owner will implement the terms and conditions contained in the federal Biological Opinion.

Verification: t least 60 days prior to the start of any project related ground disturbance activities, the project owner shall submit to the CPM a copy of the Biological Opinion. Permit terms and conditions will be incorporated into the Biological Resources Mitigation Implementation and Monitoring Plan. See also Condition of Certification **BIO-9**.

BIOLOGICAL RESOURCES MITIGATION IMPLEMENTATION & MONITORING PLAN

BIO-9 The project owner shall submit to the CPM for review and approval a copy of the final Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) and shall implement the measures identified in the plan. Any changes made to the adopted BRMIMP must be made in consultation with the CEC as well as with the Bureau of Land Management and the U. S. Fish and Wildlife Service.

Protocol: The final BRMIMP shall identify:

29. All mitigation, monitoring, and compliance conditions included in the Commission's Final Decision;
30. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation and closure;
31. All mitigation measures provided in the USFWS Biological Opinion and the CDFG Incidental Take Permit;
32. All required mitigation measures for each sensitive biological resource;
33. Required habitat compensation, including provisions for acquisition, enhancement and management, for any temporary and permanent loss of sensitive biological resources;
34. As an appendix, the Memorandum of Understanding or similar commitment document required by Condition of Certification BIO-5 detailing avoidance measures to be implemented during construction of the 700 new oil production wells, steam injection wells, and appurtenant facilities) that will be implemented to avoid and/or minimize impacts to San Joaquin kit fox as well as other sensitive species from oil and steam field construction activities;
35. All locations, on a map of suitable scale, of laydown areas and areas requiring temporary protection and avoidance during construction;
36. Aerial photographs of all areas to be disturbed during project construction activities - one set prior to site disturbance and one set subsequent to completion of mitigation measures. Include planned timing of aerial photography and a description of why times were chosen;
37. Duration for each type of monitoring and a description of monitoring methodologies and frequency;
38. Performance standards to be used to help decide if/when proposed mitigation is or is not successful;
39. All performance standards and remedial measures to be implemented if performance standards are not met;
40. A discussion of biological resource-related facility closure measures; and
41. A process for proposing plan modifications to the CPM and appropriate agencies for review and approval.
42. Terms and conditions of a CDFG Streambed Alteration Agreement, if necessary.

Verification: At least 60 days prior to start of any project-related ground disturbance activities, the project owner shall provide the CPM with the final version of the BRMIMP for this project, and the CPM will determine the plans acceptability within 15 days of receipt of the final plan. All modifications to the approved BRMIMP must be made only after consultation with CEC, BLM and USFWS. The project owner shall notify the CPM five (5) working days before implementing any CPM approved modifications to the BRMIMP.

Within 30 days after completion of project construction, the project owner shall provide to the CPM for review and approval, a written report identifying which items of the BRMIMP have been completed, a summary of all modifications to mitigation measures made during the project's construction phase, and which mitigation and monitoring plan items are still outstanding.

HABITAT COMPENSATION

BIO-10 To compensate for temporary and permanent, direct and indirect, impacts to sensitive wildlife habitat, the project owner will provide a cashier's check for $655,100 to the Center for Natural Lands Management. Additional funds may be required if additional habitat is disturbed beyond that identified in this Final Staff Assessment.

Verification: Within one (1) week of project certification, the project owner must provide written verification to the CPM that the required compensation funds have been provided to CNLM.

Within 180 days after completion of project construction, the project owner shall provide the CPM aerial photographs taken after construction and an analysis of the amount of any additional habitat disturbance beyond that identified in the Energy Commission Final Staff Assessment. The CPM will notify the project owner of any additional funds required to compensate for any additional habitat disturbances at the adjusted market value at the time of construction to acquire and manage habitat.

FACILITY CLOSURE

BIO-11 The project owner will incorporate into the planned permanent or unexpected permanent closure plan measures that address the local biological resources. The biological resource facility closure measures will also be incorporated into the Sunrise project BRMIMP. (See Condition of Certification BIO-9, above)

Protocol: The planned permanent or unexpected permanent closure plan will require the following biological resource-related mitigation measures:

43. Removal of transmission conductors when they are no longer used and useful;
44. Removal of all power plant site facilities; and
45. Measures to restore wildlife habitat to promote the re-establishment of native plant and wildlife species.

Verification: At least 12 months (or a mutually agreed upon time) prior to the commencement of closure activities, the project owner shall address all biological resource-related issues associated with facility closure in a Biological Resources Element. The Biological Resources Element will be incorporated into the Facility Closure Plan, and include a complete discussion of the local biological resources and proposed facility closure mitigation measures.

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SOIL AND WATER RESOURCES

Testimony of Joseph O'Hagan

INTRODUCTION

This report analyzes the potential adverse environmental affects associated with the construction and operation of the Sunrise Cogeneration and Power Company's (SCPC) Sunrise Cogeneration and Power Project (SCPP) in Kern County. Specifically, this report examines the potential negative impacts on the soil and water resources due to construction and operation of the power plant and associated facilities. As the project is expected to disturb approximately 61 acres during construction and operation, the nature of the soils will be examined to determine whether or not erosion control measures provided by SCPC will adequately protect soils affected by the project . In addition, the potential for the Sunrise project to adversely affect water supplies and sources in the area will be examined, such as sources of water for plant operation and the potential of waste water and steam injection to damage sensitive water sources. This testimony also addresses the project's ability to comply with all applicable federal, state and local laws, ordinances and standards, identifies mitigation measures and recommends conditions of certification.

Surface water hydrology, including flooding and drainage is addressed in the Geology section in part one of the Final Staff Assessment (FSA) that was filed on October 1, 1999. Soil contamination and solid waste disposal is also discussed in the Waste Management section of part one of the FSA released on October 1, 1999.

APPLICABLE LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

WATER POLLUTION CONTROL ACT AND CLEAN WATER ACT

The Clean Water Act (33 USC section 1257 et seq.) requires states to set standards to protect water quality. Point source discharges to surface water are regulated by this act through requirements set forth in specific or general National Pollutant Discharge Elimination System (NPDES) permits. Stormwater discharges during construction of a facility and incidental non-stormwater discharges associated with pipeline construction also fall under this act, and are addressed through a general NPDES permit. In California, the nine Regional Water Quality Control Boards (RWQCB) administer the requirements of the Clean Water Act. The Central Valley Regional Water Quality Control Board has permitting authority for the project area and sets forth administrative policies and procedures for protecting water quality in the Water Quality Control Plan for the Tulare Lake Basin (1995).

LOCAL

KERN COUNTY CODE OF BUILDING REGULATIONS

Chapter 17.28 of the County Code of Building Regulations sets forth grading requirements for certain types of land disturbance activities, including those types associated with the proposed project.

KERN COUNTY GENERAL PLAN (1994)

The general plan is the guiding document for land use and development within the county. Policies within the (Kern County 1994) pertaining to soil and water resources include:

46. Prior to the issuance of any building or grading permits, the method of water supply and sewage disposal shall be as required by the Kern County Environmental Health Services Department.

ENVIRONMENTAL SETTING

SITE DESCRIPTION

The proposed SCPP is to be located within the Midway-Sunset Oil Field, approximately 3 miles northwest of Fellows, California, in western Kern County. The proposed site currently lies at an elevation of 1,430 to 1,440 feet above mean sea level on highly dissected alluvial fan deposits descending from the Temblor Range to the west. The SCPP site is located on a broad alluvial terrace gently sloping to the east. One small, ephemeral drainage is present to the immediate north of the site (Dames & Moore 1999). This channel descends from the Temblor Range past the SCPP site and drains into the midway Valley.

The majority of the soils present at the SCPP site consist of Guijarral gravelly sandy loam with the small remaining portion belonging to the Wellport-Elkhills Association (SCPP 1998a). The Guijarral gravelly sandy loam is a very deep, very well drained soil. If undisturbed, this soil with has a slight susceptibility to water erosion and a moderate susceptibility to wind erosion. The Wellport-Elkins Association is also a well-drained soil but is found on steeper slopes than the Guijarral soil and is therefore, significantly shallower. If undisturbed, this soil is has a moderate susceptibility to both water and wind erosion.

The natural gas, boiler feed water and wastewater pipelines will only extend approximately 600 feet before connecting with the Texaco California, Inc. (TCI) utility corridor. The water supply connection with the West Kern Water District (WKWD) will extend only 40 feet from the SCPP site before connecting with an existing district pipeline. SCPC in the AFC (SCPP1998a) identified several alternative routes, A, B, and C, with route A as the preferred alternative. Subsequently, SCPC (SCPP1999k) filed a revised transmission line analysis in which route B was further divided into alternative routes D, E, F and G that run roughly 23 miles northeast from the site and terminate at the Midway Substation in the community of Buttonwillow. Routes D, E and F are parallel, and are predicated on the sharing of the route with transmission lines by SCPC and other power plant developers. Route G would run east from the SCPP site before turning north to terminate at the midway Substation. The route is approximately 20 miles long. Route A, is an approximately 15 miles long transmission line route that runs south and east from the facility site to the substation and connects with the Midway-Wheeler Ridge double circuit owned by PG&E and Department of Water Resources at the Valley Acres Substation at the California Aqueduct (SCPP 1998b). Maps depicting the soil types and tables describing pertinent soil characteristics are found in the AFC (SCPP 1998a) and supplemental filings by SCPC (SCPP1999m). In general, these transmission line alternatives cross alluvial fan deposits, valley fill, lake sediments or stream terraces formed on alluvial fans (SCPP 1998a). Most soils are generally deep and well drained except for portions of the line crossing steeper slopes where soils are generally shallow in depth. If undisturbed, the susceptibility of these soils to wind and water erosion ranges from slight to severe, generally depending upon the slope present.

The SCPP power plant will produce approximately 120,000 barrels of steam per day for enhanced oil recovery in the Midway-Sunset oil field. This amount of steam is sufficient for roughly 2000 oil production wells and associated steam injection wells. Staff assumes that steam from the project will be supplied to existing and new oil field development within a three-quarters of a mile radius of the SCPP. Roughly two-thirds (1300 wells) of the oil production and steam injection wells within this radius currently exist. Therefore, in addition to these existing wells, roughly 700 new production and injection wells are expected to be constructed. In the **Biological Resources** section, staff estimates approximately 177 acres will be permanently disturbed by this new oil field development. In addition, improvements to the existing produced water treatment facilities will be necessary as well.

The geology at the project area consists of recent alluvial deposits washed down from the Temblor Range and the Buena Vista and Elk Hills. This includes the SCPP site and the majority of the transmission line route. Beneath this alluvium is the Tulare Formation, which consists primarily of highly, stratified, deep deposits of gravel, silt, sand and clay. In portions of the transmission line crossing the Buena Vista Hills, recent alluvium is not present and the Tulare Formation represents the surface deposit. In the extreme eastern portion of the transmission line route, lake sediment from the now dry Buena Vista Lake are crossed.

Surface water resources within the area are limited to a number of ephemeral drainages. Two small, ephemeral drainages cross the proposed power plant and construction lay down sites. The watersheds of these drainages are in the foothills of the Temblor Range, resulting in 2 streams that originate approximately 2.1 miles west of the facility site and flows east through the site to Buena Vista Creek. Nineteen annual streams crossing the first 3 miles of transmission line routes also drain into Buena Vista Creek. In addition, 20 annual streams cross the final 12 miles of transmission lines, flowing to Broad Creek (SCPP 1998b). Although Buena Vista Creek and Broad Creek are usually dry, both do have the potential of reaching the California Aqueduct in major precipitation events. The California Aqueduct is located less than a mile east of the transmission line terminus near Valley Acres.

Groundwater is present within both the alluvial deposits and the Tulare Formation. This formation is separated in areas by an impermeable clay layer, known as the Corcoran Clay, into an upper and lower aquifer. Where the Corcoran Clay is present, the lower Tulare Formation is considered a confined aquifer. The upper Tulare Formation is mostly unsaturated while the lower units are saturated with both oil and water. Analysis suggests that the natural groundwater is connate water or derived at the time of deposition rather than from recharge. Information on groundwater flows of the unconfined upper and confined lower Tulare is limited, but in vicinity of the project, is probably toward the southeast.

Groundwater table elevations range from several hundred feet in depth near the SCPP site to less than 50 feet in the Buena Vista Valley (Dames & Morre 1999; Department of Energy 1997). Water quality for groundwater from the upper Tulare Formation has total dissolved solids (TDS) levels ranging from 3,000 to 6,000 mg/l. Uribe and Associates (1992) report TDS levels ranging from 2,782 to 25,583 mg/l from the upper Tulare Formation in areas near the Elk Hills. TDS levels in groundwater from the lower Tulare Formation can be even higher. Dames & Moore (1999) reports TDS levels for the lower formation to be in excess of 10,000 mg/l.

WEST KERN WATER DISTRICT

The Sunrise Cogeneration and Power Project lies within the boundary of the West Kern Water District (WKWD). This water district covers approximately 250 square miles of western Kern County and serves a population of approximately 25,000 people, residing in the Cities of Taft and Maricopa, as well as a number of unincorporated communities (WKWD 1997). The district also has approximately 400 connections for industrial users. The district’s water supply is groundwater, deliveries from the State Water Project and mutual agreements with other water agencies in Kern County (LPLG 1998a). In water year 1995-1996, total water district water demand was 13,239-acre feet of water.

WKWD is entitled to 25,000 acre-feet of State Water Project water per year through a contract with the Kern County Water Agency. An additional 10,000-acre-feet of State Water Project, known as interruptible water is also available to the district during wet years (WKWD 1997). WKWD receives the majority of its water through an in-lieu groundwater banking and pumping program with the Buena Vista Water District (BVWD). The BVWD water supply is groundwater and Kern River water. As part of the exchange, BVWD takes WKWD water from the California Aqueduct instead of pumping local groundwater (WKWD 1997). WKWD then can pump or bank a volume of groundwater that BVWD would have otherwise pumped. During high runoff years when flows in the Kern River are sufficient to meet its needs, BVWD can choose not to take the State Water Project water. At these times, WKWD is not entitled to pump groundwater.

The availability of State Water Project supplies is variable and subject to cutbacks during drought years. The district attempts each year to take the maximum amount of State Water Project available. The average volume of water banked by the District since 1979 is 11,468 acre-feet per year and the total water currently banked at the end of 1995-1996 water year is estimated at 216,503 (WKWD 1997; LPGP 1998a).

The District's well field is located approximately 15 miles northeast of Taft in the Tupman area (WKWD 1997). Sediments here are derived from the Kern River fan. The thickness of the fresh groundwater bearing sediments beneath the well field are estimated to be about 800 feet thick. This aquifer appears to be generally unconfined, with some small clay lenses providing very localized confined conditions. Recharge is through the use of spreading ponds and natural recharge from the Kern River. Groundwater quality is good, with TDS levels of 290 mg/l (WKWD 1997).

Total peak production capacity of the six active wells is 99 acre-feet per day, but maximum daily usage averages approximately 41.5 acre-feet per day (WKWD 1997). The district has another agreement with the BVWD to pump 3,000 acre-feet of groundwater per year. This water cannot be banked and therefore the district uses this water first (WKWD 1997). The district must recharge the basin for the amounts pumped in excess of 3,000-acre feet. Average basin recharge between 1979 and 1996 has been 11,250 acre-feet (WKWD 1997). Because of water treatment requirements, groundwater is provided for all domestic uses.

ENVIRONMENTAL IMPACTS

PROJECT SPECIFIC IMPACTS

EROSION AND SEDIMENTATION

The construction of the facility will disturb approximately 65 acres, of which 26 acres consist of soils at the SCPP and laydown area. The remaining acres will mainly be disturbed during the installation of concrete support structures for the associated transmission line, assess road improvement and switchyard. Additional soil disturbance will be incurred by above ground piping for natural gas, steam, Heat recovery steam generator (HRSG) feedwater and wastewater interconnections. While pipeline construction should not require any significant amount of excavation, soil disturbance and compaction due to heavy equipment operation will occur.

Accelerated wind and water induced erosion may result from earth moving activities associated with construction of the proposed project. Removal of the vegetative cover and alteration of the soil structure leaves soil particles vulnerable to detachment and removal by wind or water. Typical of an arid environment such as the western San Joaquin Valley, rainfall may be intense, which greatly enhances the potential for water erosion. Grading activities may redirect runoff into areas more vulnerable to erosion. Areas where linear facilities cross drainages are also vulnerable to erosion.

The existing topography at the power plant site will be leveled to 1,430 feet above sea level (ASL). Vegetation removal and earth moving activities are anticipated at the 23-acre laydown area. Similar soil disturbance will be expected for the installation of transmission lines and above ground interconnection pipeline systems. Topographic maps provided in the Soil and Water Resources Sections indicates a drainage flowing east to Buena Vista Creek to the south of the project where interconnections will be made. This annual stream is within 600 feet of the south boundary of the project site and could transport eroded soil particles from interconnection construction.

SCPP has proposed a transmission line corridor (Route B) with three alternatives (Routes D, E, and F). This corridor consists of consolidating one or more transmission lines planned by other developers with the SCPP transmission line. Route D would connect the SCPP to a future Midway-Sunset Cogeneration Project (MSCP) switchyard, and then would connect MSCP and Midway with a joint-ownership transmission line. Route E would connect the SCPP and MSCP then would connect MSCP to the proposed La Paloma switchyard with a joint-ownership transmission line, and then would connect all parties to the Midway substation with a joint-ownership transmission line. Route F would connect the SCPP to the proposed La Paloma switchyard, and then would connect La Paloma and Midway with a joint-ownership transmission line. The acreage disturbed for the transmission line corridor represents those alternatives that would disturb the largest area.

Transmission lines will be constructed along existing service/access roads to minimize soil disturbance from heavy equipment and reduce the need for the construction of new access roads.

During project operation, wind and water action can continue to erode unprotected surfaces. An increase in the amount of impervious surfaces can increase runoff, leading to the erosion of unprotected surfaces. SCPP (1999a, Data Response 59) has provided a draft Erosion Control and Stormwater Management Plan that identifies potential temporary and permanent erosion and stormwater runoff control measures. This plan is discussed further under Mitigation below. Streambed alteration permit requirements for transmission line crossing of natural drainages is discussed in the Biological Resources section of this document.

The SCPP power plant will produce approximately 120,000 barrels of steam per day for enhanced oil recovery in the Midway-Sunset oil field. This amount of steam is sufficient for roughly 2,000 oil production wells and associated steam injection wells. Within the ¾-mile radius circle around the proposed power plant, which staff considers to be the sphere of influence of the steam produced by the power plant, roughly two-thirds (1,300 wells) of the oil production wells and steam injection wells currently exist. In addition to these existing oil production wells and steam injection wells, roughly one-third (700 wells) will be new and need to be constructed. In addition to the new production and injection wells, the existing produced water facility will have to be expanded (SCPP 1999m). Improvements to the existing produced water treatment facilities will be necessary for the SCPP, however all improvements will occur within the existing 10-acre produced water treatment facility (Radian 1999f).

Staff has estimated that these elements will disturb an additional 176.4 acres. For a discussion of how this figure was calculated, please see the **Biological Resources** section of this document.

The potential for erosion and sedimentation associated with development of the steamfield deal primarily with the generation of fugitive dust. The extensive earth moving activities associated with construction of the SCPP project will not be necessary for steamfield development. For fugitive dust control, please see the **Air Quality** section of this document.

WATER SUPPLY

The proposed SCPP facility will obtain water for domestic, fire fighting and evaporative make-up uses from the West Kern Water District (WKWD). The source of the WKWD water is groundwater from wells located in the Tupman area. The project will connect to potable water lines used to supply the communities of Taft and McKittrick.

SCPP will also use produced water from the TCI oil fields for the heat recovery steam generators (HRSG). Produced waters refers to generally brackish groundwater brought to the surface during oil and natural gas production. Oilfield produced water is filtered and softened at an existing TCI water treatment facility two miles from the power plant site (SCPP 1999g, data response 66). Current capacity at the treatment facility is 125,000 barrels per day (16-acre feet per day). This will be soon expanded to 275,000 barrels per day (35-acre feet per day) to accommodate the project.

Produced water from the oilfield is treated by removing entrained oil using air flotation, removing suspended solids by using filtration units and reducing water hardness by using strong acid cation exchange water softeners (SCPP 1999e, data response 65). Incoming produced water on the average contains 100-ppm solids and oil and 210-ppm hardness (measured as $CaCO3$) and 3,000-ppm total dissolved solids. Treated water has on the average 1-ppm solids and oil and less than 2-ppm hardness (SCPP 1999e).

Demineralized water supply for the combustion turbine generator wash, approximately 780 gallons per day (gpd), will be generated onsite as needed for on-line and off-line washing or produced on-site using a small reverse osmosis unit and a portable self-contained demineralizing system. SCPP will, on average, require 70,100-gpd from WKWD and 529,600-gpd from Texaco California, Inc. (TCI). Maximum water demand for WKWD and TNAP water supplies will be 248,100-gpd and 415,800-gpd, respectively (SCPP 1998). Because of higher operating temperatures, maximum make-up water demand for the HRSGs is actually less than the average demand. Average annual demand of WKWD is calculated to be 78.6 acre-feet while TCI demand is calculated to be 6,194 acre-feet (SCPP 1998). Maximum annual water usage of WKWD and TCI water supplies are calculated to be 277.9 acre-feet and 6,067 acre-feet, respectively (SCPP 1998a). However, this steam will be condensed and recycled, reducing slightly the over all TCI produced water demand. The project, over the course of a year, will operate in both average and maximum modes, therefore, actual annual water demand is probably somewhere between these two numbers. In addition, the above noted annual water consumption figures do not account for any plant downtime. Accounting for plant downtime will result in an approximate 5 percent reduction in the annual consumption figures.

Service of the proposed project by WKWD will not adversely affect the district's water supply. Domestic water supply demands within the district are projected to decrease in the future as oil field operations are anticipated to decrease (WKWD 1997). Industrial demand is increasing, however; this is discussed further under Cumulative Impacts. Peak water demand within the district during this time period occurred in 1983-84 when 17,403 acre-feet of water were sold (WKWD 1997). Demand for WKWD has generally declined over the last 25 years and has significantly declined between 1984 and 1999. However, if domestic water demands were to increase or water supplies were to decrease due to drought conditions, WKWD would be able to rely on banked water supplies to provide for SCPP demands (SCPP 1998).

The use of produced water for the vast majority of project water needs will not adversely affect groundwater resources. The quality of produced water, although it varies greatly, is not suitable for domestic and agricultural uses. Indeed, CURE (1999l) and the Department of Toxic Substances Control ([DTSC] Metz 1999) have concerns that the produced water, if disposed, may be hazardous waste. This is discussed further below. Generally, produced water resulting from oil field operation is re-injected into the aquifer. Use of this water source by the project reduces demand on fresh water supplies.

WATER QUALITY

Incorrect disposal of wastewater, contaminated stormwater runoff or inadvertent chemical spills can degrade soil, surface water and groundwater. SCPC (SCPP1998a; 1998b) has proposed to manage all waste streams in order to prevent the contamination of surface water and groundwater bodies. As mentioned earlier, erosion can contribute a significant amount of sediment to local streams when soils are disturbed due to facility construction operations. Construction operations will adhere to best management practices to ensure minimal pollution of surface waters from erosion. All runoff and liquids entering facility drains will be collected and routed to the Valley Waste system for appropriate disposal.

Groundwater in the area of the SCPP is the most likely body of water to be threatened by facility operation. As noted above, groundwater is encountered beneath the project site at depths as deep as 300 feet. Approximately 300-gpd of septic waste will be disposed of in a septic tank and tile leach field. (SCPP 1998a). According to SCPC, this septic system will by serving 20 or more people per day in a commercial environment, this system may potentially be included in the proposed Environmental Protection Agency Class V injection well regulations. These proposed regulations state that new cesspools serving 20 or more people per day and discharging waste in an area that is a potential source of drinking water will be banned. SCPC (SCPP1998a) states that groundwater in the vicinity of the proposed facility is of quality unsuitable for drinking water due to high TDS concentrations well in excess of drinking water standards. However, the enforcement of this restriction on cesspools is contingent on the completion of the State of California's Source Water Assessment Program (SWAP), to be completed and approved by the United States Environmental Protection Agency (EPA) in May 2003. Upon completion, any region with potable bodies of groundwater will be required to enforce the proposed cesspool regulations.

A second source of potential groundwater contamination is the disposal of wastewater and certain stormwater runoff streams through injection wells by Valley Waste Disposal Company. The waste stream will originate from off-line combustion turbine generator washing, wastewater from the transformer sump drains and various facility drains that is pooled in an underground waste water tank prior to transport to Valley Waste Disposal Company's Buena Vista II injection wells. Originally, SCPC (SCPP 1998a) indicated there would be no boiler feed water treatment on-site. In supplemental information supplied by SCPC (SCPP 1999r), however, feedwater will be treated as needed by a small two gallons per minute reverse osmosis unit. A small waste stream from this unit will be routed to the wastewater collection basin and eventually to Valley Waste (SCPP 1999r, Appendix A).

Stormwater that could be potentially contaminated will be collected from curbed or walled areas covering approximately 0.18 acres in size and routed to the wastewater collection basin prior to being routed to Valley Waste with other project wastewater streams for disposal. Containment areas are enclosed by curbs with a minimum height of 12 inches. Based upon a 100-year, 24 hour storm, SPCC (SCPP1999e) estimates that stormwater runoff flows to the wastewater collection basin would be 14 gpm. The capacity of the disposal tank is 7,500 gallons. The capacity of the pumps transferring the wastewater to the pipeline to Valley Waste is 500 gpm, more than sufficient capacity to handle the anticipated flows.

The stormwater generated in areas not subject to contact with contaminants will drain to drainage ditches and directed off site to natural drainage channels. Drainage issues are discussed further in the **Geology** section of part one of the FSA.

The project applicant has indicated that it is their belief that, because drainage would be segregated, that a NPDES General Industrial Permit is not required for the operation of the project. Staff of the RWQCB agrees with this assessment (Waas 1999). SPCC (SCPP 1998a) estimates that 7,200 gpd (171 barrels per day) will be discharged to Valley Waste.

In addition, an unspecified volume of produced water will result from the addition of new production wells due to the availability of steam from the project. In general, the volume of produced water is equal to the amount of steam injected for thermal enhanced oil recovery. Excess produced water will be also be disposed of through injection wells at Valley Waste. Texaco Corporation, International (TCI) is entitled to dispose of up to 63,644 barrels per day ([8.2 acre feet per day] Bright 1999). In addition, water softener re-generation brine from the water treatment facility is sent to Valley Waste for disposal. Currently, approximately 12,000 barrels per day is discharged to Valley Waste. Valley Waste has sufficient capacity to accommodate the additional volumes from new production wells as well as from the power plant (Bright 1999).

The Valley Waste facility that is proposed for use by SCPC for disposal of wastewater streams from the SCPP is the Buena Vista Facility #2. This facility is located approximately 3 miles from the proposed project site and consists of six primary oil/water separation ponds and seven contingency ponds and 26 Class II injection wells. Class II injection wells are defined as injection or disposal wells associated with oil and gas field operations and are permitted by the Division of Oil, Gas and Geothermal Resources (DOGGR). As noted above, the ponds are permitted by the RWQCB. Only non-hazardous wastewater may be accepted at this facility. Oil and Gas field development, which includes wastewater from an oil field related cogeneration facilities such as the SCPP, are exempt from the federal Resource Conservation and Recovery Act (42 U.S.C. Section 6921 et seq.). California does not exempt, however, oil and gas field related wastes that display hazardous waste characteristics as identified in Title 22, California Code of Regulations, Article 2, Section 66261.10 et seq. Wastewater meeting California's hazardous waste criteria cannot be disposed of through the use of injection wells.

As noted above, CURE (1999l) has indicated that it believes that the ambient levels of benzene, mercury and perhaps other constituents in the produced water exceed California hazardous waste thresholds. In addition, even if the produced water does not meet the hazardous waste criteria, the brine from the waste treatment facility in the oil field and wastewater from the cogeneration facility may exceed hazardous waste levels. SCPC declined CURE's data requests for information on a full characterization of the produced water and resulting wastewater streams. Staff felt this information on the produced water was publicly available and did not support CURE's request. Subsequently, CURE and staff were unable to locate this information through agency contacts. CURE (1999l) did an exhaustive review of what information is available from DOGGR and the RWQCB and collected enough information to suggest to DTSC that the produced water and/or resulting wastewater streams resulting from treating the produced water may be hazardous. As noted above, hazardous wastewater cannot be disposed of through the use of injection wells (Riley 1999) without pre-treatment to make the wastewater non-hazardous. Alternative disposal methods, such as sending the hazardous streams to a Class I waste disposal facility that accepts liquid waste. In addition, if the produced water is hazardous, treatment of this water at the water treatment facility and/or the cogeneration plant may be construed as hazardous waste treatment and require permitting of the facilities accordingly (Riley 1999). Staff is currently working with DTSC staff to write data requests asking SCPC to fully characterize the produced water, all treatment processes and resulting waste streams.

In addition, SCPC (SCPP 1998a) originally proposed that two Class II underground injection wells be constructed at the site to dispose of low-quality HRSG steam (SCPP 1998a). Now, however, SCPC (Soares 1999) plans to condense the steam and recycle the water. The revised water demand figures identified above reflect the recycling of this water (SCPP 1999r).

CUMULATIVE IMPACTS

Temporary and permanent disturbance associated with construction of the proposed project will cause accelerated wind and water induced erosion. Mitigation measures proposed by SCPP should ensure that the proposed project would not contribute to cumulative erosion and sedimentation impacts (SCPP Data Response 1999). Additional development in the Midway-Sunset oil field will result both from operation of the proposed project and from non-project related oil field development. Concerns relating to this deal mainly with dust control which is discussed in the Air Resources Section. In addition, proposed linear facilities and structures will not remove any currently productive agricultural lands from cultivation. The reliance on produced water for facility operations will avoid any impacts on local drinking or agricultural water supplies.

Currently, water demand for WKWD is approximately 13,000-acre feet per year. The recently certified La Paloma Power Project will receiving approximately 6,000 acre feet of the district's State Water Project entitlement (out of a potential total of 25,000 acre feet per year) directly from the California Aqueduct. The proposed Elk Hills Power Project will require approximately 3,200 acre feet per year; while the proposed Midway Sunset will require approximately 3,100 acre feet per year (Patrick 1999). In addition to the existing demand, the new power plant projects and the 280 acre feet per year required for the SCPP, leaves WKWD with approximately 2,500 acre feet per year to accommodate future growth. As noted above, the district sees domestic demand declining in the future. Staff is not aware of any additional major projects within the district that would put additional demands on the district's water supply. Given the vast amount of water banked by the district, supplying the proposed project under even extreme drought conditions would not create a hardship for the district or their other customers.

As noted above, Valley Waste's Buena Vista Number 2 facility has the capacity to accommodate the increased brine wastewater flow from the water treatment facility due to the project as well as wastewater flows from the proposed project. Given the uncertainty of whether these wastewater flows to Valley Waste are hazardous, further discussion of this issue will have to wait.

FACILITY CLOSURE

A planned, unexpected temporary or permanent closure of the proposed SCPP should not be a significant concern site drainage, and potential for erosion are properly dealt with for any possible closure. Unexpected permanent closure may pose the threat of drainage and erosion problems due to a lack of maintenance of the facilities. Staff will require SCPC to address this concern in their closure plan.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

With implementation of the identified mitigation measures, the proposed project will comply with all applicable LORS dealing with erosion control and stormwater management. Verification of potential drinking water sources per completion of the local SWAP will be required before the construction and operation of the septic tank and associated leach field. As stated above, Commission staff does not anticipate the presence of any underground sources of drinking water and do not feel this is an issue.

Potential compliance of the project with California hazardous waste regulations, if applicable, must wait further information from the applicant.

Finally, CURE (Fox 1999) indicates that, although Valley Waste is complying with the waste discharge requirement from the RWQCB for the ponds at the Buena Vista Number 2 facility, requirements within the permit are inconsistent with water quality objectives contained in the Water Quality Control Plan for the Tulare Lake Basin (Basin Plan). It should be noted that Valley Waste fully complies with its permit conditions. The need for updating the waste discharge requirement is acknowledged by the RWQCB staff and they indicate that they are working on this issue (Grey 1999). Given these efforts, hazardous waste issues aside, staff feels that the need to update Valley Waste's permit is best dealt with by the RWQCB and is not a reason to allow the project not to utilize this facility for wastewater disposal.

MITIGATION MEASURES

SCPC PROPOSED MEASURES

PROTECTION OF SOIL RESOURCES

Soil-1: Prepare a detailed Erosion Control Plan prior to construction and implement the plan during and after construction. Surface soil protection may include the use of mulches, synthetic netting material, and riprap; the installation of a sediment detention basin on the downgrade edge of the Sunrise Project site; and the compacting of native soil.

Soil-2: Conduct all grading operations in compliance with the Kern County Grading Ordinance.

Soil-3: Conduct all construction activities in accordance with California's General Industrial Storm Water Permit for Construction Sites, including the erosion control measures under Soil-1 and Best Management Practices (BMPs) to reduce erosion and the transport of increased suspended sediment from construction areas.

Soil-4: Stabilize soil in areas that will be disturbed by construction but not compacted or covered by pavement or concrete structures. This stabilization will apply in particular to the areas disturbed by construction of the transmission line supports. To stabilize the areas, 4-inches of topsoil should be selectively removed, stored, and replaced. In areas of excavation, soil should be graded and compacted to ensure that removed soil is not left in irregular piles that are more susceptible to water and wind erosion. Seeding will be performed in the areas where natural vegetation has been distressed or removed by construction activity.

SCPC (SPCC 1999h, Data Response 59) has provided a draft Erosion Control and Stormwater Management Plan that identifies temporary and permanent erosion and stormwater control measures. Furthermore, the intent of this plan, when finalized, is to serve as the stormwater pollution prevention plan as required under the General Construction and Industrial Activity Stormwater Permits issued by the State Water Resources Control Board.

The draft plan identified a number of potential best management practices for the construction and operation phases of the project.

BEST MANAGEMENT PRACTICES THAT REDUCE EROSION AND SEDIMENT-LADEN STORMWATER RUNOFF

- Mulching on disturbed soils or in combination with temporary or permanent seeding strategies;
- Direct runoff away from disturbed areas by means of temporary drainage ways;
- Stabilize plant site roadways with compaction or gravel;
- Utilize soil stabilizers as appropriate and as required in Air Permit conditions;
- Straw bale barriers to intercept sediment-laden runoff from small areas of disturbed soil;
- Check dams to reduce erosion of existing drainage channels and to promote sedimentation behind the dam;
- Silt fencing to promote sedimentation behind silt fence; and
- Stormwater retention basins to retain runoff and allow excessive sediment to settle out.

BEST MANAGEMENT PRACTICES TO PREVENT STORMWATER CONTAMINATION

- Provide secondary containment for hazardous material delivery and storage areas to prevent spills or leakage of fluid materials from contaminating soil or soaking into the ground;
- Covered dumpsters and waste containers; and
- Designate storage areas for construction wastes.
- Provide for proper storage of hazardous materials, paints, and related products;
- Train employees on the proper use of materials such as fuel, oil, asphalt and concrete compounds, acids, glues, solvents, etc.;

- Implement a spill prevention and control plan;
- Timely remove construction wastes; and
- Store all liquid wastes in covered containers.

PROTECTION OF WATER RESOURCES

Water-1: Designs and construction practices will minimize soil erosion during construction and operation of all associated facilities. The site drainage plan will conform to the Kern County Flood District Design and Procedure Manual.

Water-2: Stormwater management during operation will consist of collecting stormwater from within bermed and confined areas and will be routed to the TCI wastewater interconnection to the Valley Waste system

Water-3: Equipment refueling and maintenance during construction will be performed within designated areas consistent with BMPs. Spill contingency plans will be prepared and followed where appropriate.

Water-4: During construction of transmission lines, existing roads will be used as much as possible.

Water-5: During construction, a buffer area will be established using stakes or fences along the intermittent drainage located to the north and northwest of the cogeneration facility. No heavy equipment operation will be permitted within those areas to ensure the drainage will not be disturbed.

Water-6: During operation, the minimum conditions required to maintain exemption from the California General Stormwater Permit will be maintained and documentation sufficient to certify those conditions will be retained onsite.

SPILL PREVENTION

Spill containment measures will be provided for chemical storage. The containment structure for the aqueous ammonia storage tank will be sized for 110 percent of the tank capacity. All other chemical storage tank and all outdoor containment structures will have a volume equal to at least the capacity of the largest single tank in the contained area. Concrete curbs will be provided for anhydrous ammonia delivery areas. At this time, SCPC has not indicated that precipitation events are considered in the design of containment structures. Storm events must be considered in designing spill control structure as precipitation may fill the basin and allow the spilled product to breech the containment structure berms.

SITE DRAINAGE

The site drainage system will be designed to comply with all applicable federal, state, and local regulations. Onsite drainage will be accomplished by gravity flow, whenever possible. Runoff with possible contamination will be routed to a wastewater drain tank prior to discharge to the TNAP wastewater interconnection. All other runoff will flow through the facility by gravity through cement culverts and ditches. Once off site, uncontaminated runoff waters will follow existing natural drainage patterns (SCPP 1998a).

CONCLUSIONS AND RECOMMENDATIONS

Staff cannot recommend certification of the proposed project at this time due to questions regarding potential hazardous waste treatment and disposal.

CONDITIONS OF CERTIFICATION

SOIL&WATER 1 Prior to beginning any clearing, grading or excavation activities associated with project construction, the project owner will develop and implement a Storm Water Pollution Prevention Plan (SWPPP).

Verification: Two weeks prior to the start of construction, the project owner will submit to the Energy Commission Compliance Project Manager (CPM) a copy of the Storm Water Pollution Prevention Plan (SWPPP).

SOIL&WATER 2 Prior to the initiation of any earth moving activities, the project owner shall submit an erosion control and revegetation plan for staff approval. The final plan shall contain all the elements of the draft plan with changes made to address the final design of the project.

Verification: The final erosion control and revegetation plan shall be submitted to the Energy Commission CPM for approval 30 days prior to the initiation of any earth moving activities.

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